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(45) **Date of Patent: Feb. 23, 2016**

(54) **METHOD AND APPARATUS FOR ISOLATING AND TREATING DISCRETE ZONES WITHIN A WELLBORE**

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(51) **Int. Cl.**

E21B 23/06 (2006.01)
E21B 33/128 (2006.01)
E21B 43/26 (2006.01)

(52) **U.S. Cl.**

CPC ***E21B 23/06*** (2013.01); ***E21B 33/128*** (2013.01); ***E21B 43/26*** (2013.01)

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CPC E21B 33/12; E21B 33/1208; E21B 23/06; E21B 34/14; E21B 33/128; E21B 23/01; E21B 33/122

See application file for complete search history.

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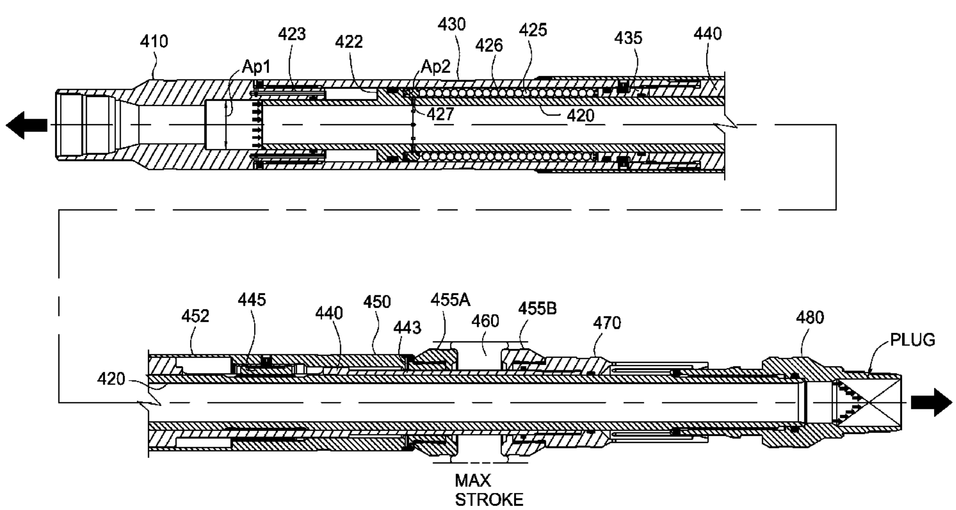
(57) **ABSTRACT**

Methods and apparatus for conducting fracturing operations using a wellbore fracturing assembly are described. The assembly may be mechanically set and released from a wellbore using a coiled tubing string. The assembly may include a pair of spaced apart packers for straddling the area of interest, an injection port disposed between the packers for injecting fracturing fluid into the area of interest, and an anchor for securing the assembly in the wellbore. At least one of the packers includes a pressure balanced mandrel. After conducting the fracturing operation, the assembly may be relocated to another area of interest to conduct another fracturing operation.

38 Claims, 15 Drawing Sheets



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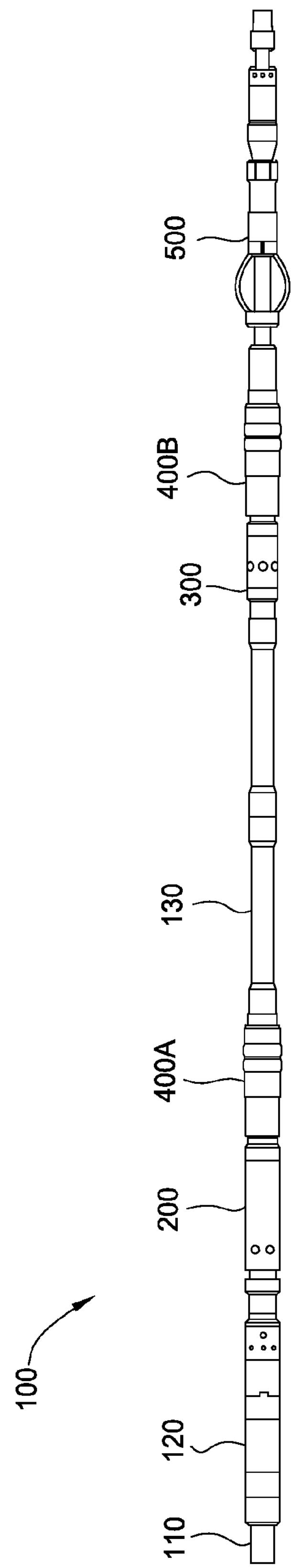

FIG. 1

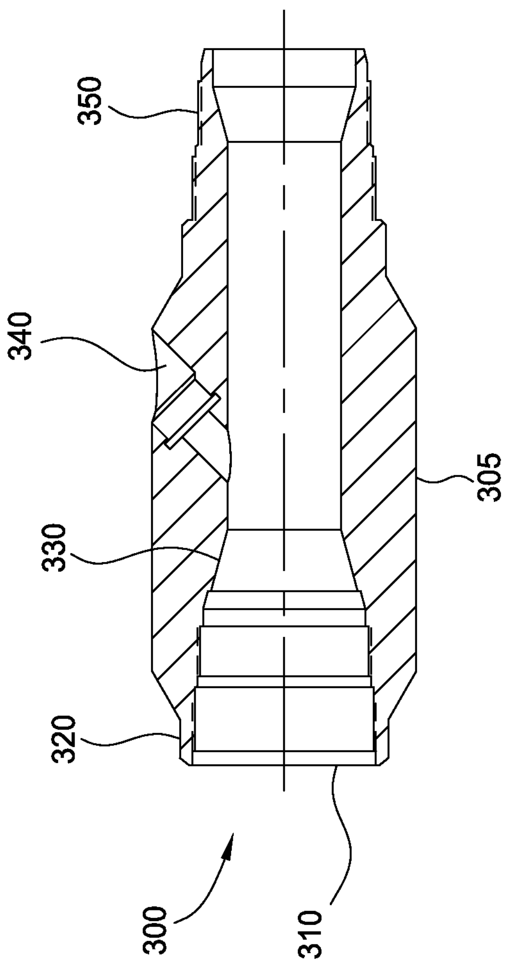

FIG. 2

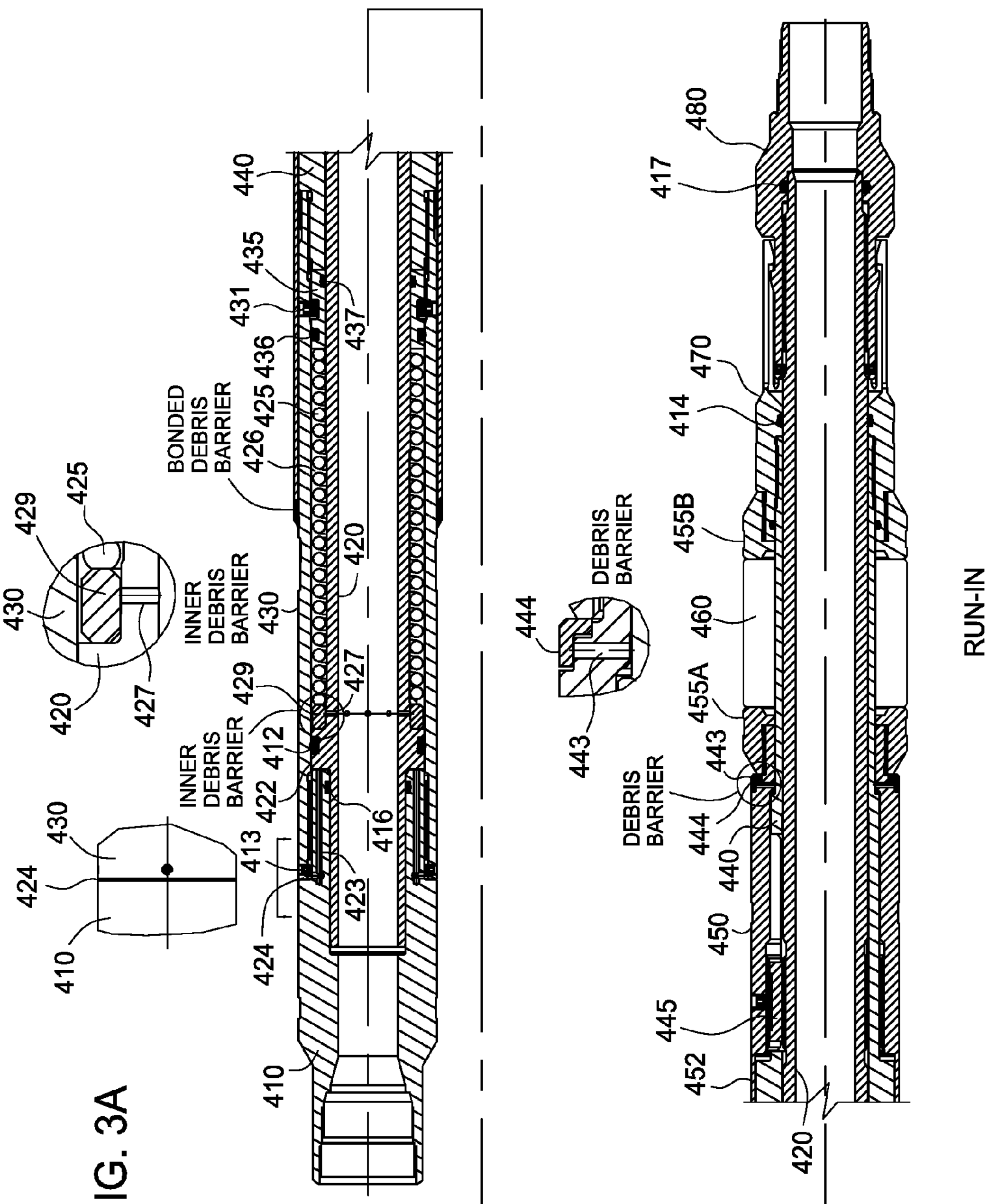

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FIG. 3A

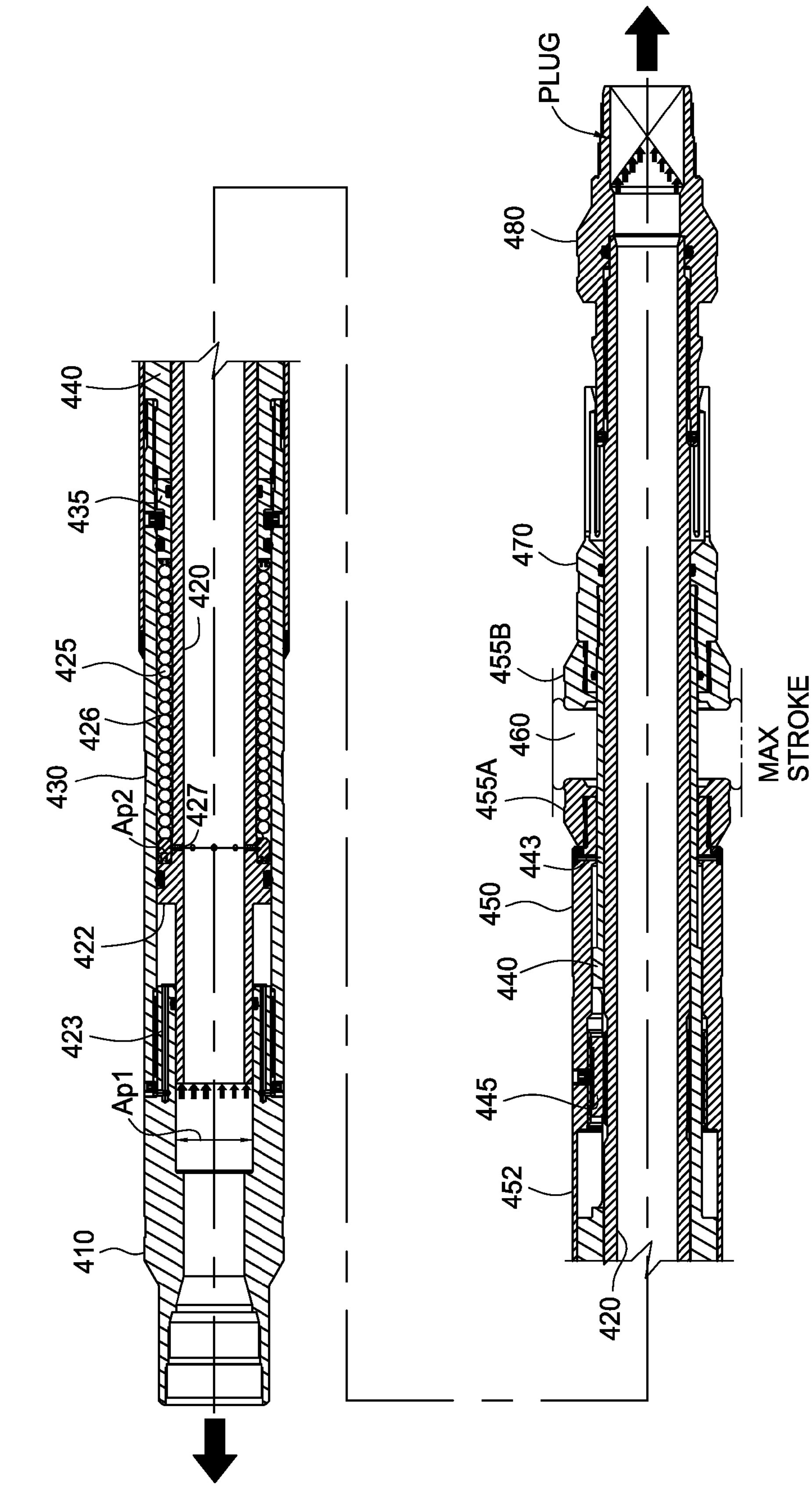
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FIG. 3B

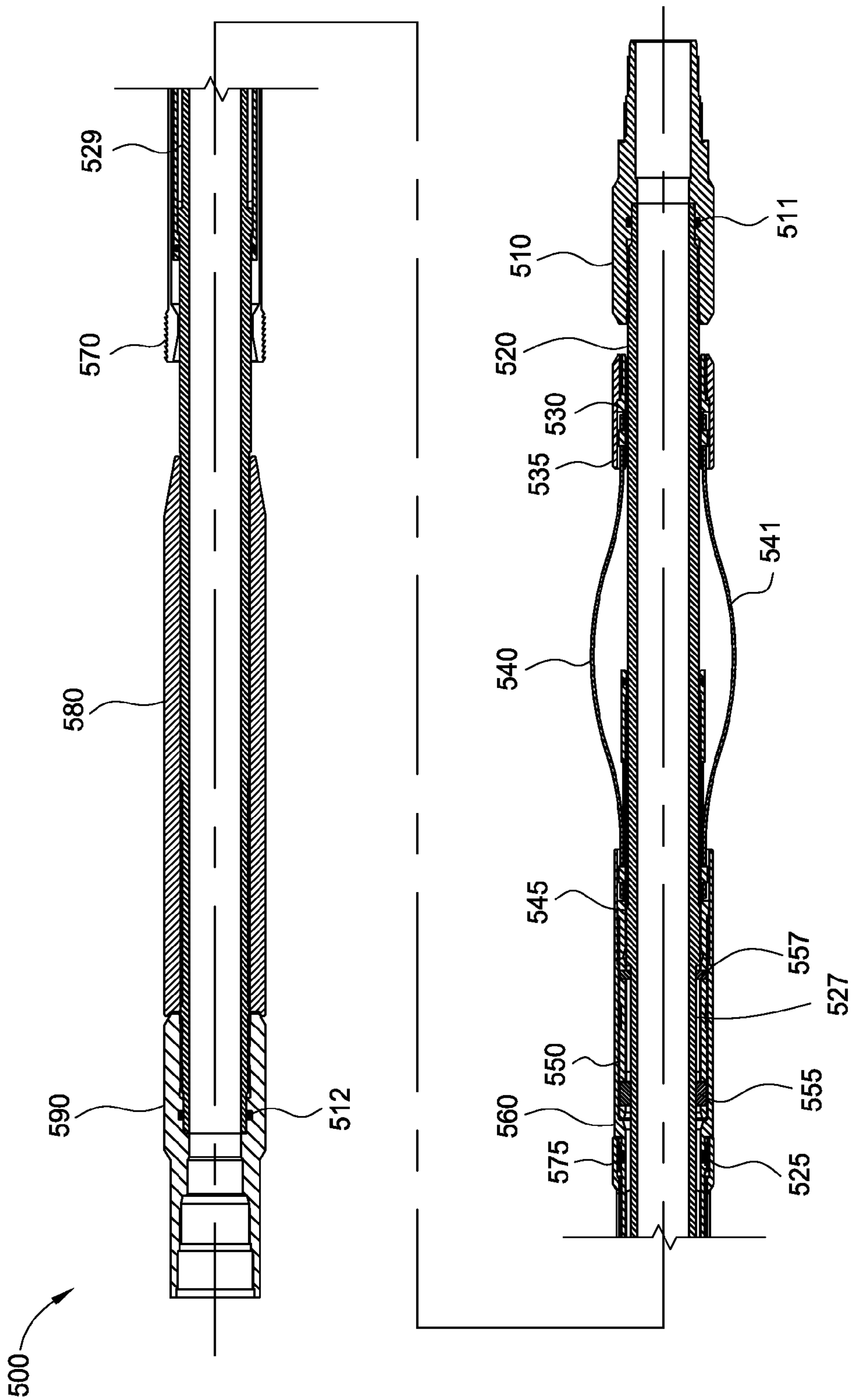
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FIG. 4A

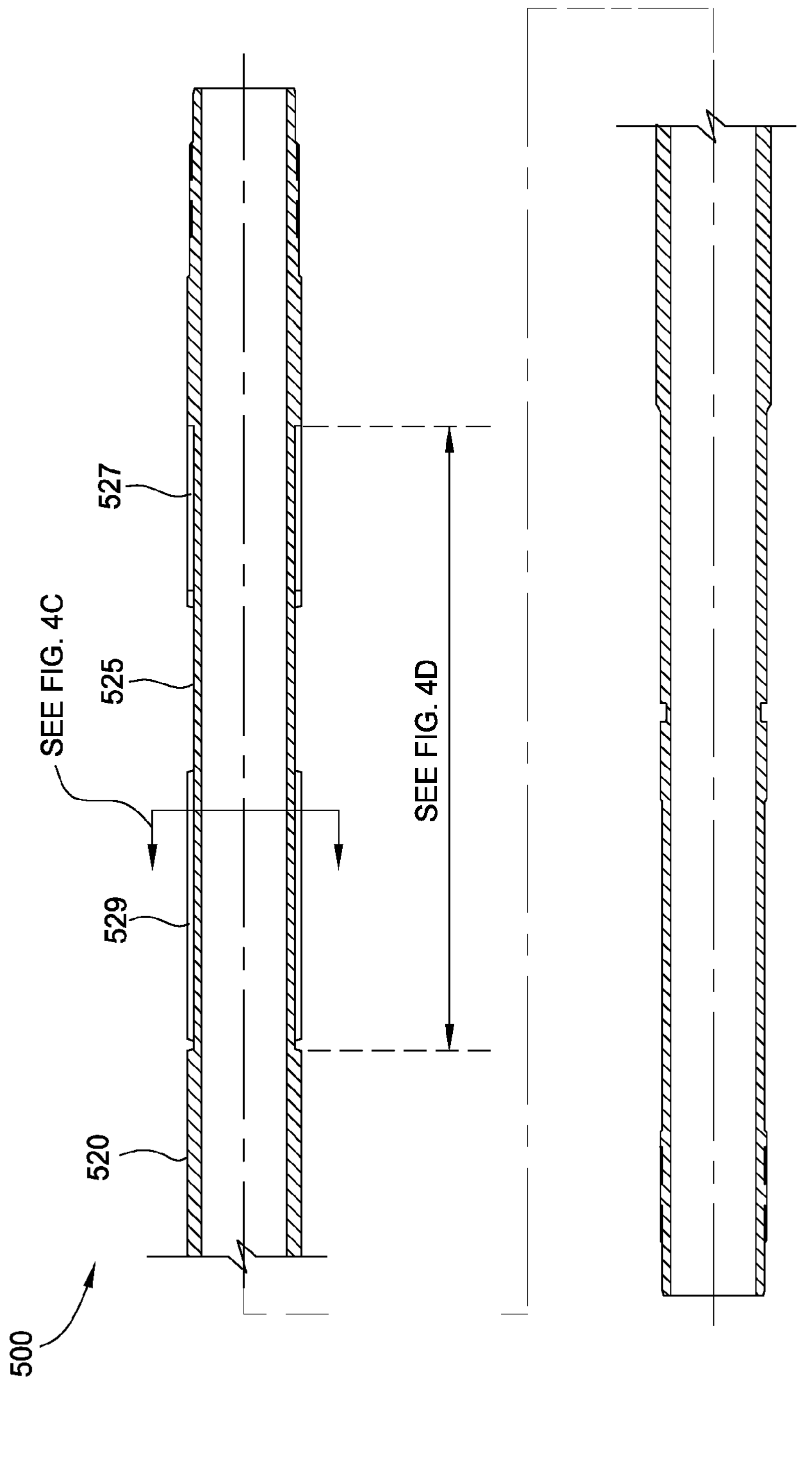

FIG. 4B

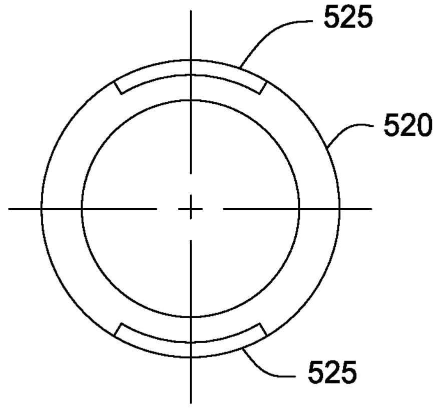

FIG. 4C

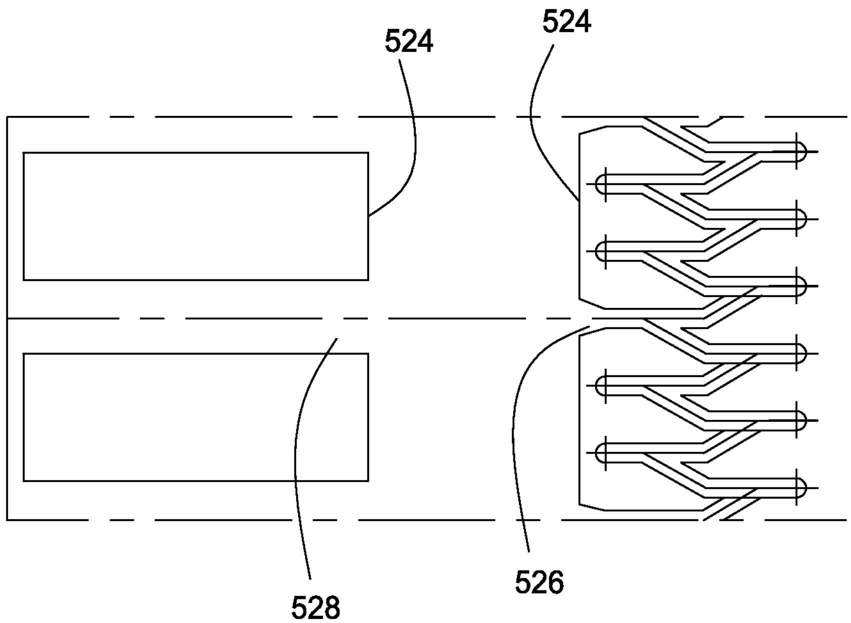

FIG. 4D

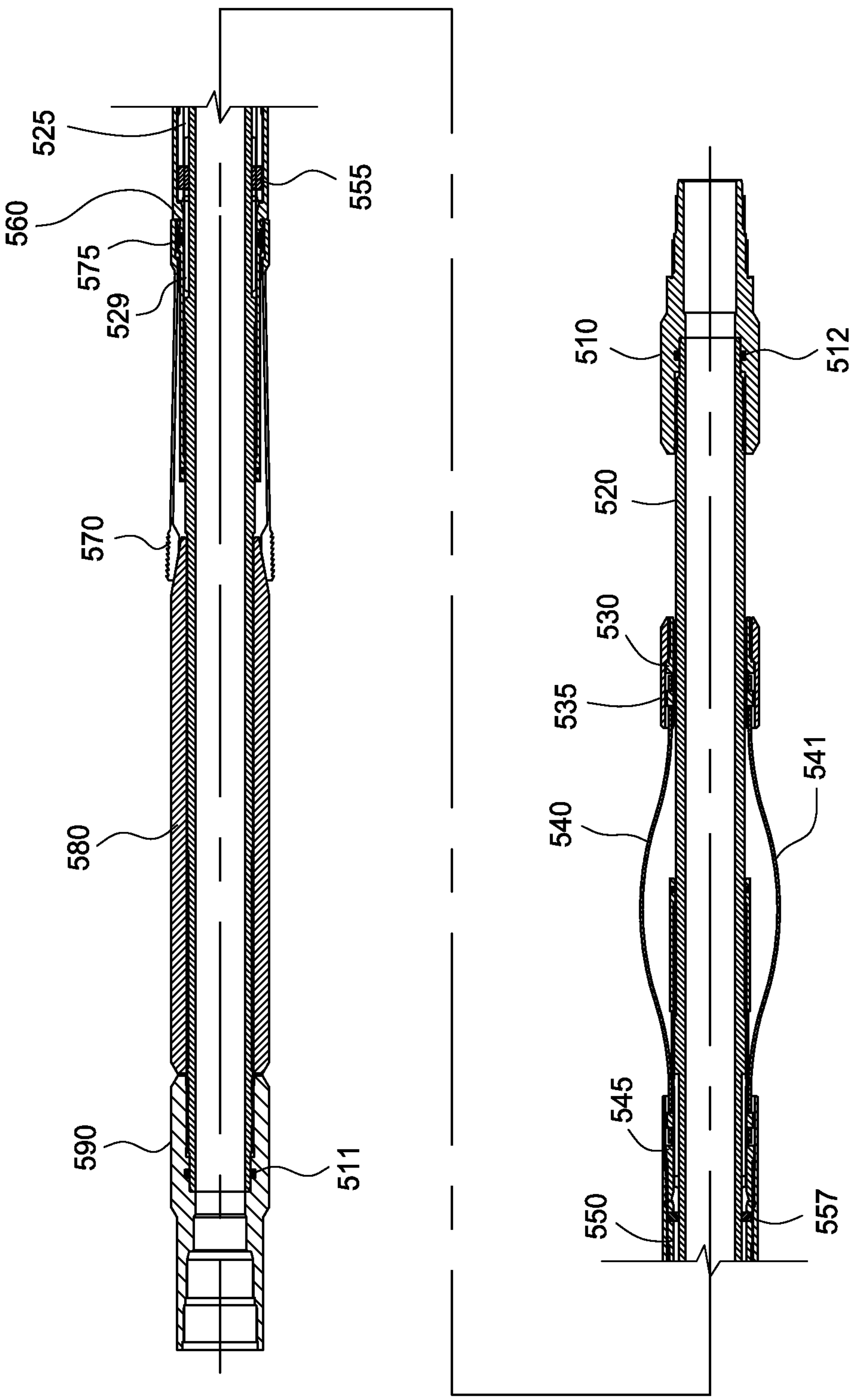
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FIG. 4E

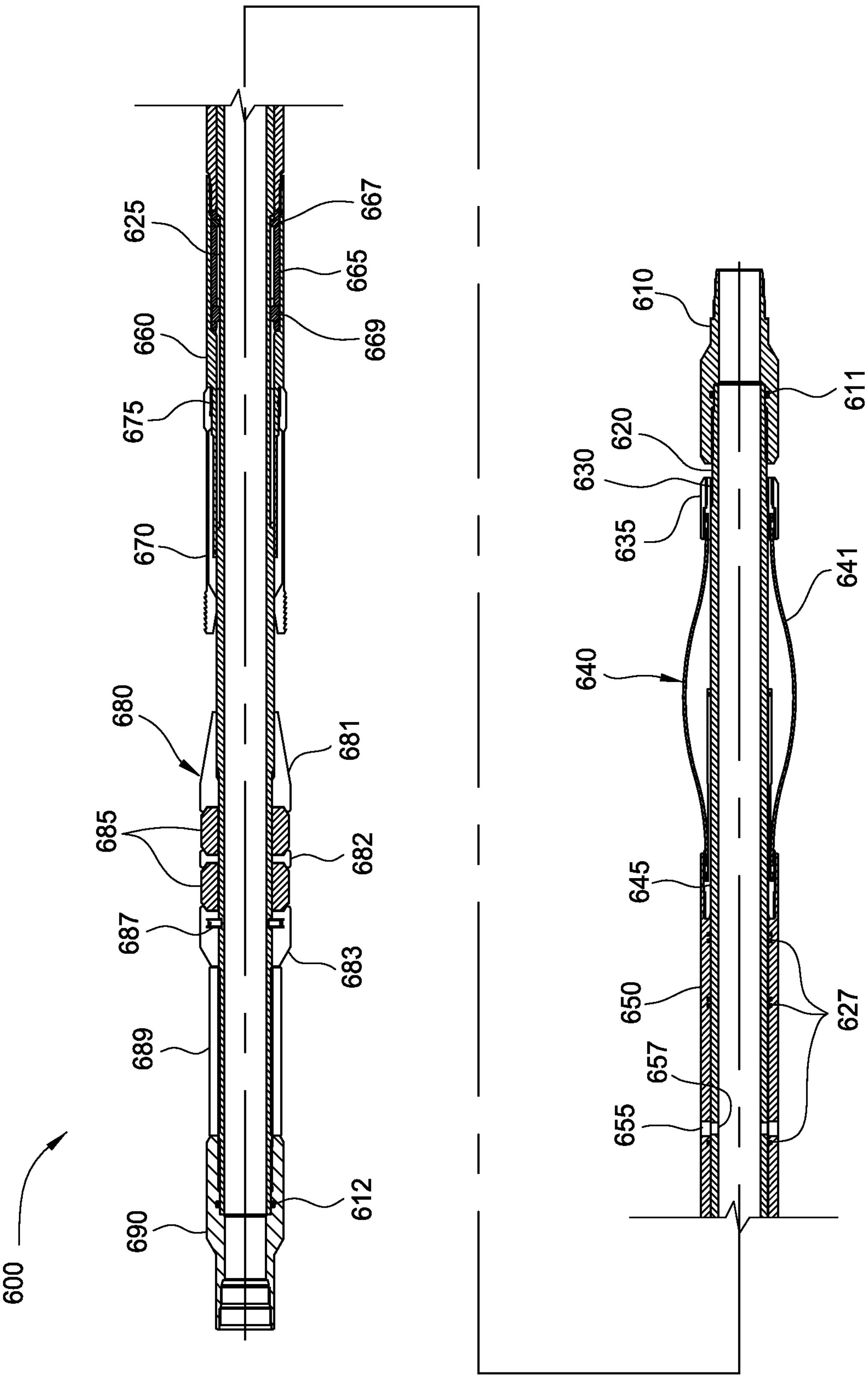
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FIG. 5A

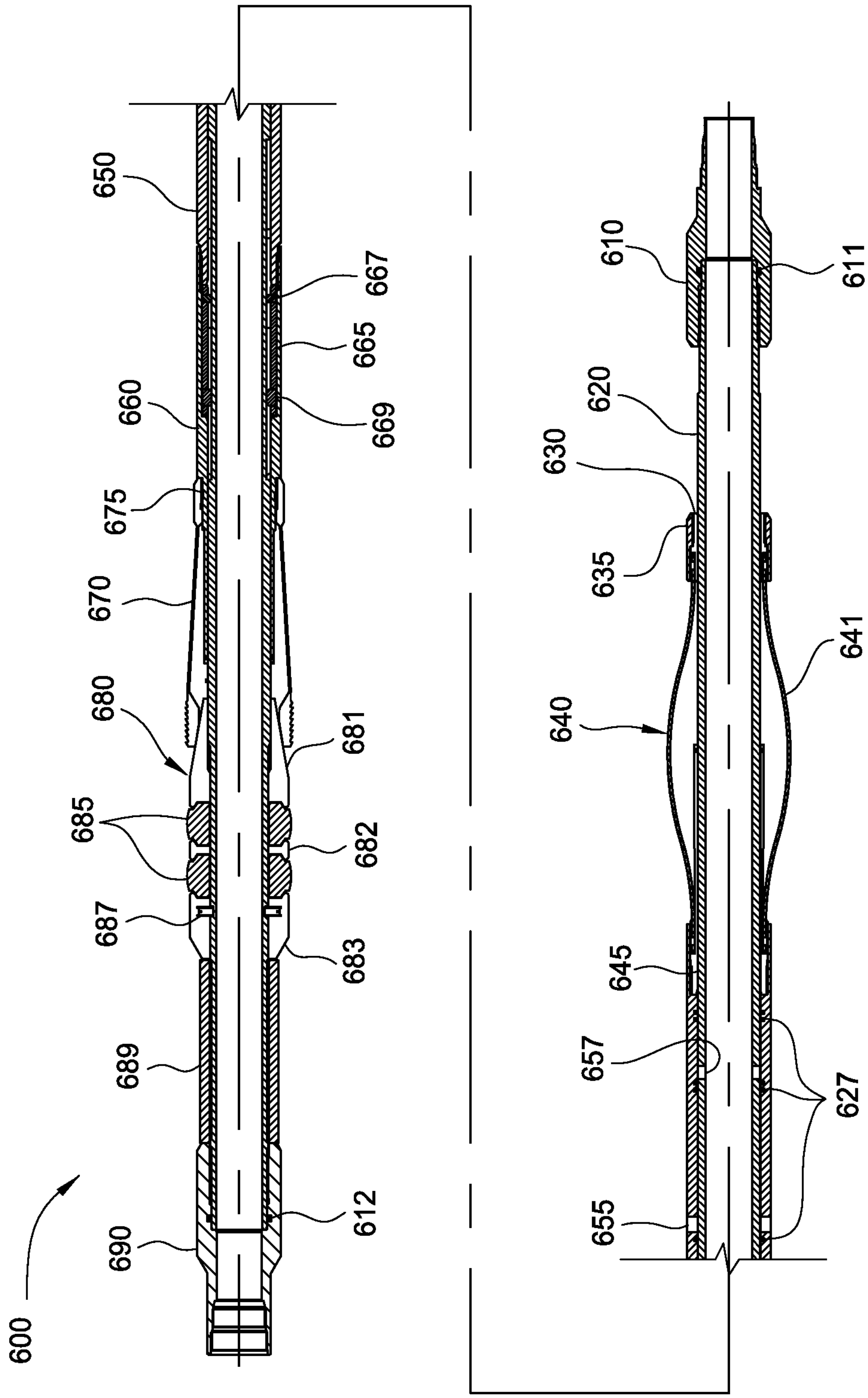
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FIG. 5B

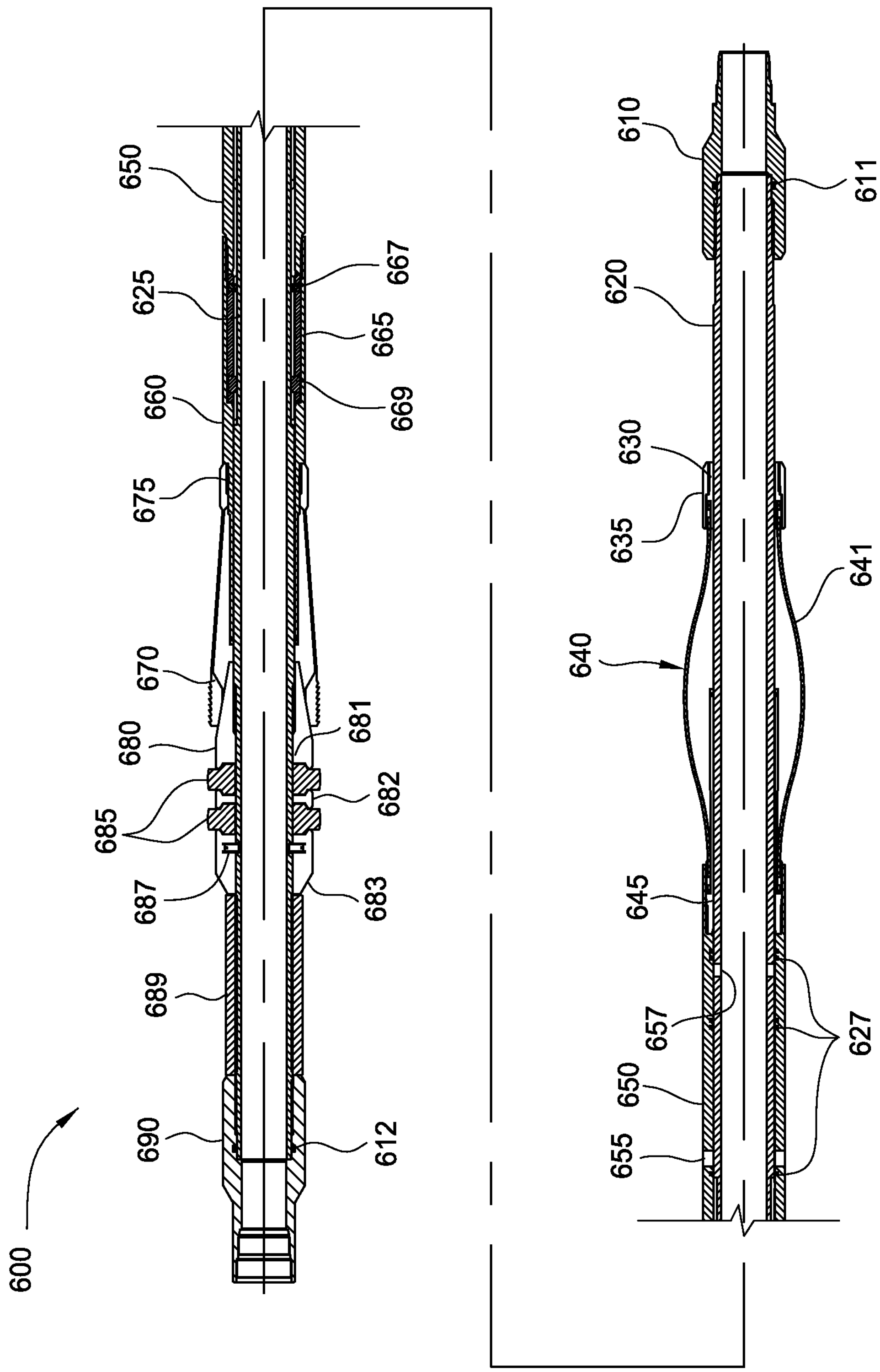
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FIG. 5C

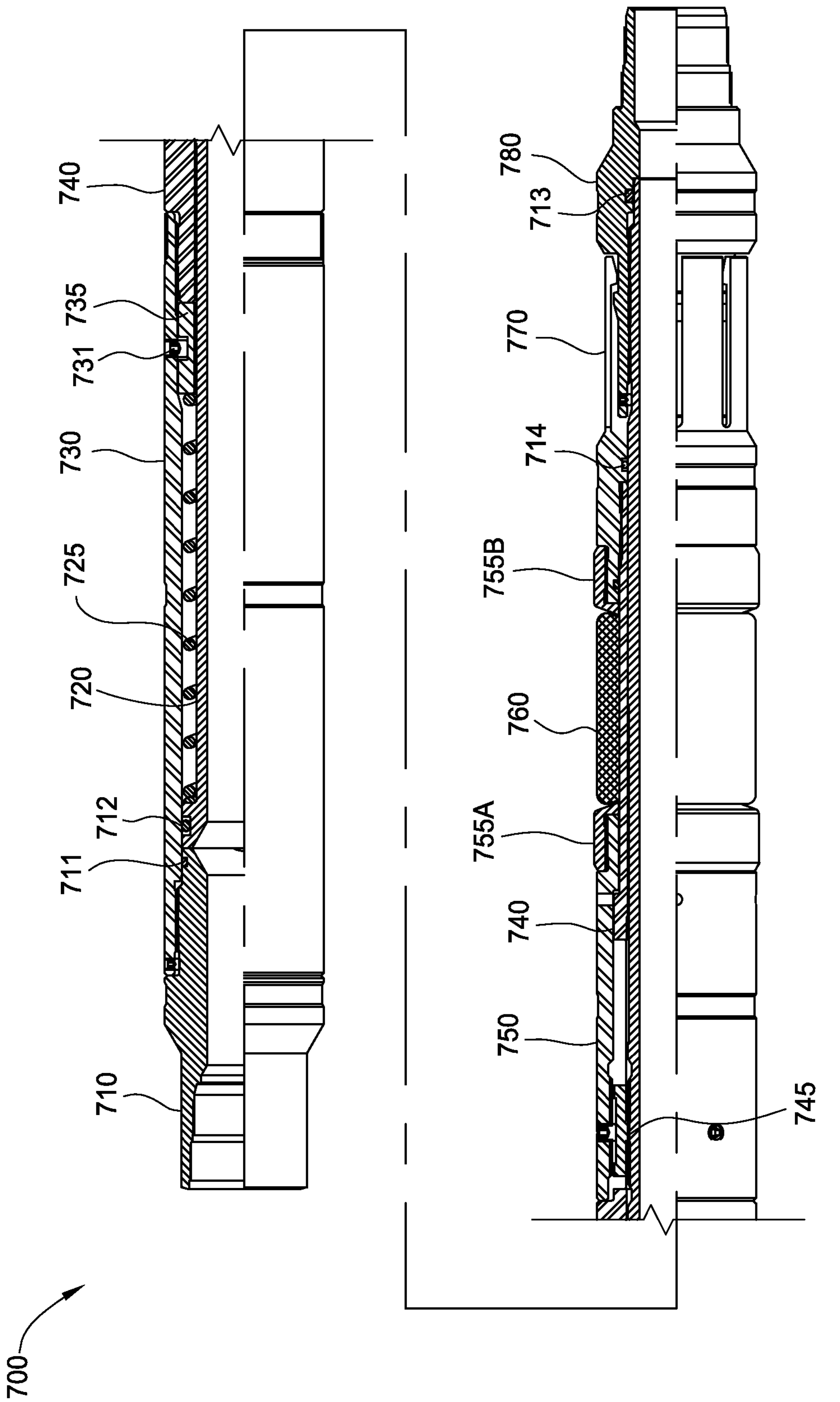
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FIG. 6A

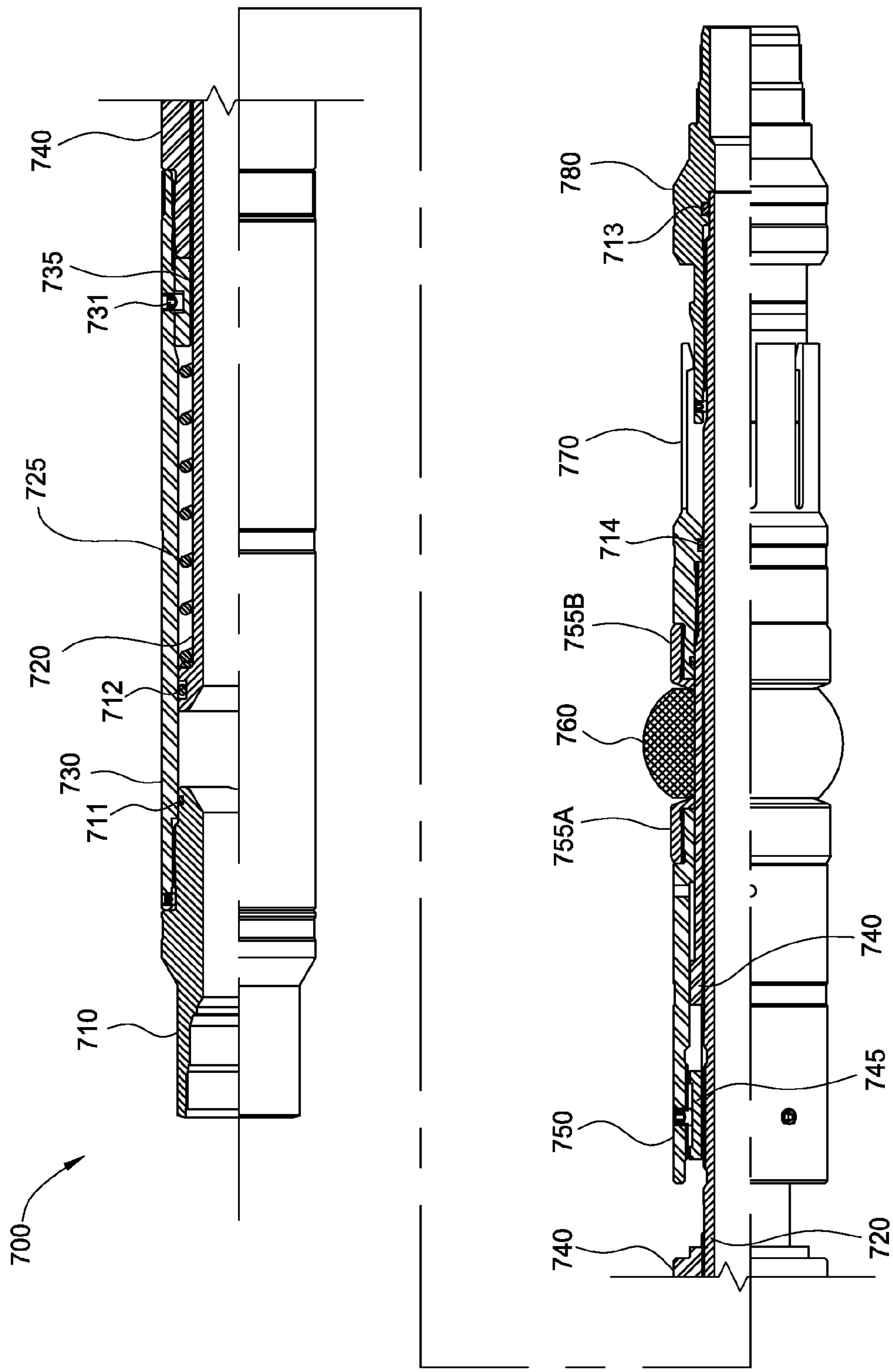
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FIG. 6B

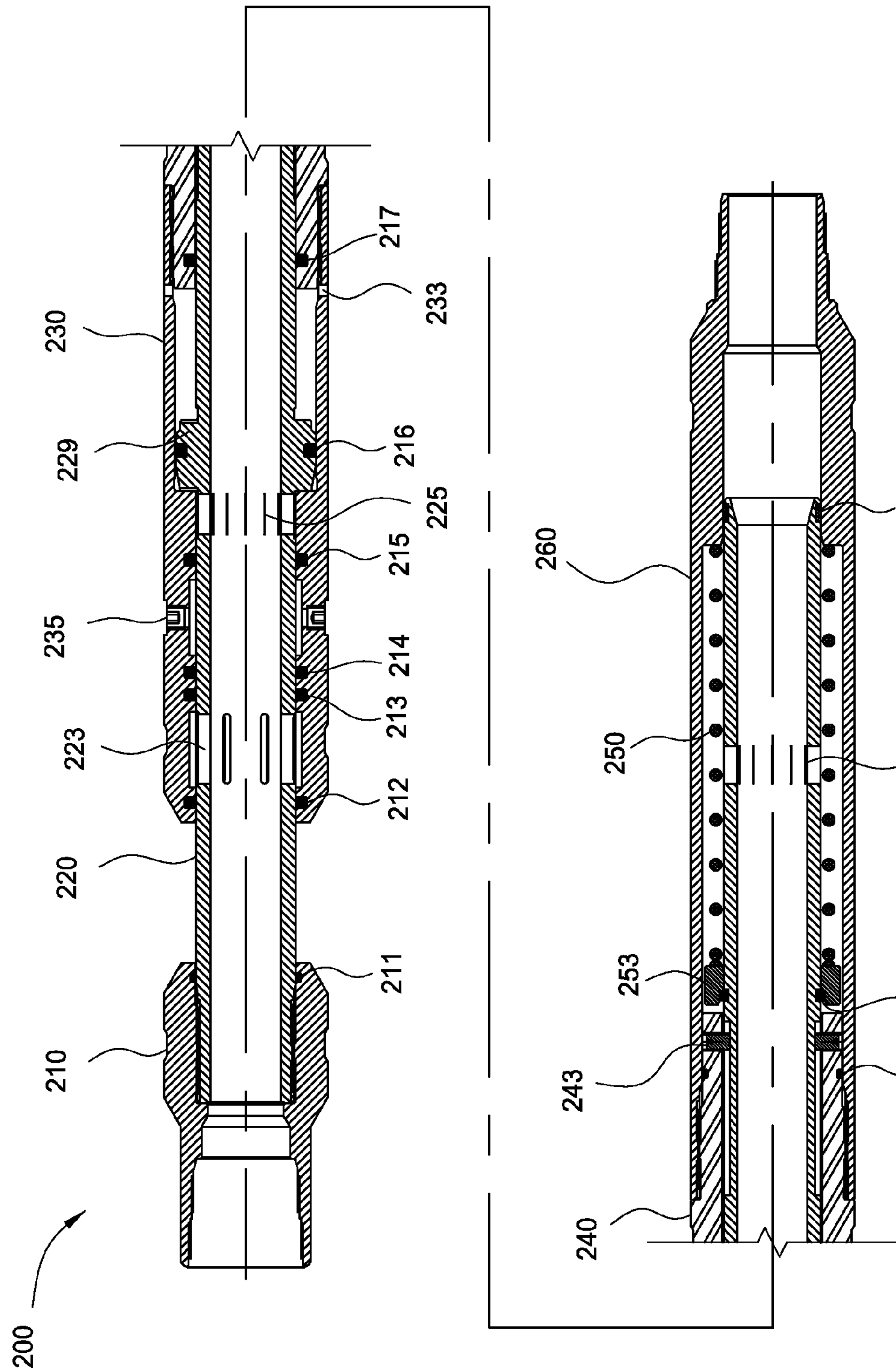
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FIG. 7A

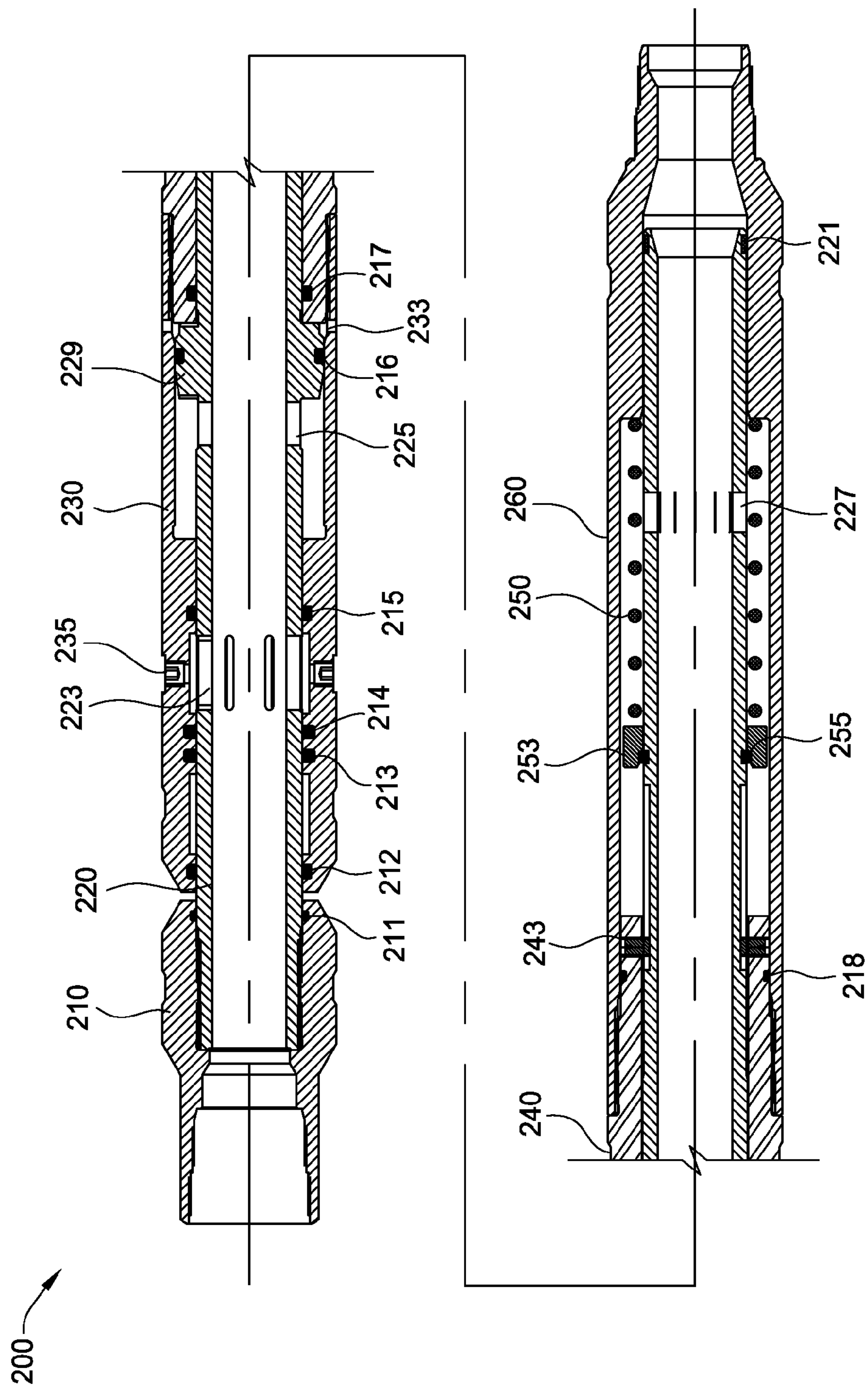
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FIG. 7B

METHOD AND APPARATUS FOR ISOLATING AND TREATING DISCRETE ZONES WITHIN A WELLBORE

CROSS-REFERENCE TO RELATED APPLICATIONS

This application claims benefit of U.S. Provisional Patent Application No. 61/393,748, filed Oct. 15, 2010, which application is incorporated herein by reference in its entirety.

BACKGROUND OF THE INVENTION

1. Field of the Invention

Embodiments of the present invention relate to a mechanically set packer suitable for use to isolate a zone in a wellbore. In one embodiment, the packer includes a pressure balanced mandrel to facilitate release of the packer. In another embodiment, the packer includes a pressure balanced mandrel to prevent application of excessive hydraulic force on the packing element. In yet another embodiment, the present invention relates to an assembly of packers for isolating a zone within a wellbore.

2. Description of the Related Art

In certain wellbore operations, it is desirable to "straddle" an area of interest in a wellbore, such as an oil formation, by packing off the wellbore above and below the area of interest. A sealed interface is set above the area of interest and another sealed interface is set below the area of interest. Typically the area of interest undergoes a treatment, such as fracturing, to assist the recovery of hydrocarbons from the straddled formation.

A variety of straddling tools are available, the most common being a cup-type tool. These tools are effective at shallow depths but may have maximum depth limitations at around 6,000 feet due to the swabbing effect induced on the wellbore liner by the tool coming out of the hole. Another type of tool includes hydraulically actuated packers disposed above and below an area of interest. However, this hydraulically actuated tool relies on a valve to open and shut to allow a fluid back pressure to set the packers, which is susceptible to flow cutting during pumping operations.

There is a need, therefore, for a mechanically actuated packer having a pressure balanced mandrel. There is also a need for a mechanically actuated packer whose actuation or de-actuation is not affected by the fluid pressure flowing therethrough. There is a further need for a wellbore isolation assembly equipped with a tension actuated packer having a pressure balanced mandrel.

SUMMARY OF THE INVENTION

Embodiments of the invention generally relate to methods for conducting wellbore treatment operations and apparatus for a wellbore treatment assembly.

BRIEF DESCRIPTION OF THE DRAWINGS

So that the manner in which the above recited features of the invention can be understood in detail, a more particular description of the invention, briefly summarized above, may be had by reference to embodiments, some of which are illustrated in the appended drawings. It is to be noted, however, that the appended drawings illustrate only typical embodiments of this invention and are therefore not to be considered limiting of its scope, for the invention may admit to other equally effective embodiments.

FIG. **1** illustrates a side view of a wellbore treatment assembly according to one embodiment of the invention.

FIG. **2** illustrates a cross sectional view of an injection port according to one embodiment of the invention.

FIG. **3**A illustrates a cross sectional view of a packer in an unset position according to one embodiment of the invention.

FIG. **3**B illustrates a cross sectional view of the packer in a set position according to one embodiment of the invention.

FIG. **4**A illustrates a cross sectional view of an anchor in an unset position according to one embodiment of the invention.

FIG. **4**B illustrates a cross sectional view of an inner mandrel of the anchor according to one embodiment of the invention.

FIG. **4**C illustrates a top cross sectional view of the inner mandrel of the anchor according to one embodiment of the invention.

FIG. **4**D illustrates a track and channel layout of the inner mandrel according to one embodiment of the invention.

FIG. **4**E illustrates a cross sectional view of the anchor in a set position according to one embodiment of the invention.

FIG. **5**A illustrates a cross sectional view of an anchor in an unset position according to one embodiment of the invention.

FIG. **5**B illustrates a cross sectional view of the anchor in a set position according to one embodiment of the invention.

FIG. **5**C illustrates a cross sectional view of the anchor in a pack-off position according to one embodiment of the invention.

FIG. **6**A illustrates a cross sectional view of a packer in an unset position according to one embodiment of the invention.

FIG. **6**B illustrates a cross sectional view of the packer of FIG. **6**A in a set position.

FIG. **7**A illustrates a cross sectional view of an unloader in a closed position according to one embodiment of the invention.

FIG. **7**B illustrates a cross sectional view of the unloader in an open position according to one embodiment of the invention.

DETAILED DESCRIPTION

The invention generally relates to an apparatus and method for conducting wellbore treatment operations. As set forth herein, the invention will be described as it relates to a wellbore fracturing operation. It is to be noted, however, that aspects of the invention are not limited to use with a wellbore fracturing operation, but are equally applicable to use with other types of wellbore treatment operations, such as acidizing, water shut-off, etc. To better understand the novelty of the apparatus of the invention and the methods of use thereof, reference is hereafter made to the accompanying drawings.

FIG. **1** is a side view of a wellbore fracturing assembly **100** according to one embodiment of the invention. In general, the assembly **100** is lowered into a wellbore on a coiled tubing string **110** at a desired location. Other types of tubular or work strings having tubing or casing may also be used with the assembly **100**. To "straddle" or sealingly isolate an area of interest in a formation, the assembly **100** is mechanically set in the wellbore by pulling and pushing on the coiled tubing string **110**, thereby placing the assembly **100** in tension and securing the assembly **100** in wellbore and straddling the area of interest. After the assembly **100** is set in the wellbore, a fracturing operation may be conducted through the assembly **100** and directed to the isolated area to fracture the area of interest and recover hydrocarbons from the formation. Upon completion of the fracturing operation, the assembly **100** is mechanically unset from the wellbore by pulling and pushing on the coiled tubing string **100** to release the tension, thereby unstraddling the area of interest and releasing the assembly **100** from the wellbore. The assembly **100** may then be relocated to another area of interest in the formation and re-set to conduct another fracturing operation. As described herein with respect to unsetting the assembly **100**, the application of one or more mechanical forces to achieve the unsetting sequence may be accomplished merely by releasing the tension which had been applied to set the assembly **100** in place initially, or may be supplemented by additional force applied by springs within the components and/or by setting weight down on the assembly **100**.

As illustrated, the assembly **100** may include an adapter sub **120**, an unloader **200**, packers **400**A and **400**B, an injection port **300** disposed between the packers **400**A and **400**B, and an anchor **500**. The assembly **100** may also include one or more spacer pipes **130** disposed between packers **400**A and **400**B to adjust the straddling length of the assembly **100** depending on the size of the area of interest in the formation to be isolated and/or fractured. In one embodiment, the adapter sub **120** is coupled at its upper end to the tubing string **110** and is coupled at its lower end to the unloader **200**. The lower end of the unloader **200** is coupled to the upper end of the packer **400**A, which is coupled to the spacer pipe **130**. The injection port **300** is coupled to spacer pipe **130** at one end and is coupled to the packer **400**B at its opposite end. Finally, the anchor **500** is located at the bottom end of the assembly **100**, specifically the anchor **500** is coupled to the lower end of the packer **400**B.

In operation, the assembly **100** is lowered on the tubing string **110** into the wellbore adjacent the area of interest in the formation for conducting a fracturing operation. Once the assembly **100** is positioned in the wellbore, the assembly may be raised and lowered to create an "up and down" motion by pulling and pushing on the tubing string **110** to actuate and set the anchor **500**. After the anchor **500** is set and the assembly **100** is secured in the wellbore, tension is further applied to the assembly **100** by pulling on the tubing string **110**. The tension in the assembly **100** is utilized to actuate and set the packers **400**A and **400**B to straddle the area of interest in the formation. The tension in the assembly **100** is also utilized to set the unloader **200** into a closed position to prevent fluid communication between the unloader **200** and the annulus surrounding the assembly **100**. The assembly **100** is then held in tension to conduct the fracturing operation.

A fracturing and/or treating fluid, including but not limited to water, chemicals, gels, polymers, or combinations thereof, and further including proppants, acidizers, etc., may be introduced under pressure through the tubing string **110**, the adapter sub **120**, the unloader **200**, the packer **400**A, and the spacer pipe **130**, and injected out through the injection port **300** into the area of interest of the formation between the packers **400**A and **400**B. In one embodiment, the assembly **100** may include more than one injection port **300** to facilitate the fracturing operation by reducing the velocity of flow through the injection port **300**. In one embodiment, the wellbore and/or wellbore casing or lining may have been perforated adjacent the area of interest to facilitate recovery of hydrocarbons from the formation.

In one embodiment, a device, such as a plug or a check valve, may be located below the assembly **100** to prevent the fracturing and/or treating fluid from flowing through the bottom end of the assembly **100** and to allow pressure to build within the assembly **100** and the area of interest in the formation between the packers **400**A and **400**B during the fracturing operation. In one embodiment, a device, such as a circulation sub (not shown), may be located above the assembly **100** or the packer **400**A. The circulation sub may initially allow a two-way fluid communication flow between the assembly **100** and the wellbore surrounding the assembly **100** as the assembly **100** is located in the wellbore. A ball or dart may subsequently be introduced into the circulation sub to prevent fluid flow from the internal throughbore of the assembly **100** to the wellbore surrounding the assembly **100** but allow fluid flow from the wellbore surrounding the assembly **100** to the throughbore of the assembly **100**, to permit a fracturing operation.

In one embodiment, one or more seats (not shown) may be located in series within the assembly **100**, below the injection port **300**, which are configured to receive a ball or dart to close fluid communication through the throughbore of the assembly **100** to permit a fracturing operation. Upon completion of the fracturing operation, the pressure within the assembly **100** may be increased to an amount such that the ball, dart, and/or the seat are extruded through assembly **100** or displaced within the throughbore of the assembly **100** to open fluid communication through the throughbore of the assembly **100** below the injection port **300** to the wellbore surrounding the assembly **100**. This open fluid communication may also help equalize the pressure differential across the lower packer **400**B to assist unsetting of the packer **400**B. The assembly **100** may then be moved to another location in the wellbore and/or another ball or dart may then be introduced on another seat to conduct another fracturing operation. In an alternative embodiment, the one or more seats may be collets that are operable to receive the ball or dart to close fluid communication within the assembly **100** and that are shearable to subsequently allow the ball or dart to be moved to open fluid communication within the assembly **100**.

In one embodiment, a device, such as an overpressure valve (not shown), may be located below the assembly **100** to assist in the fracturing operation. The overpressure valve may be actuated, biased, or preset to close fluid communication between the assembly **100** and the wellbore, below the packer **400**B, thereby allowing pressure to build in the work string below the injection port **300** and preventing fluid from continuously flowing through the remainder of the work string. Upon completion of the fracturing operation, the pressure within the assembly **100** may be increased to a pressure that temporarily actuates the overpressure valve into an open position to release the pressure within the assembly **100** and to open fluid communication between the assembly **100** and the wellbore surrounding the assembly **100** below the packer **400**B. This pressure release may also help equalize the pressure differential across the packer **400**B to help facilitate unsetting of the packer **400**B. As the pressure drops within the assembly **100**, the overpressure valve may then be actuated or biased into a closed position, thereby closing fluid communication between the assembly **100** and the wellbore below the packer **400**B.

After the fracturing operation is complete, the tension in the tubing string **110** and the assembly **100** is released, which may be facilitated by pushing on the tubing string **110**. The tension release allows the unloader **200** to actuate into an open position to permit fluid communication between the unloader **200** and the annulus surrounding the assembly **100** to equalize the pressure above and below the packer **400**A to help unsetting of the packer **400**A. The tension release also allows the packers **400**A and **400**B and the anchor **500** to unset from engagement with the wellbore. The assembly **100** may then be removed from the wellbore. Alternatively, the assembly **100** may be relocated to another area of interest in the formation to conduct another fracturing operation.

In one embodiment, the assembly **100** may include only one packer **400**A or **400**B that is utilized to conduct the wellbore treatment operation. The packer **400**A or **400**B may be used to isolate the area of interest by sealing the wellbore either above or below the area of interest. The packer **400**A or **400**B may be operated as described herein.

In one embodiment, the assembly **100** may include measurement tools to determine various wellbore characteristics. Such measurement tools may include as temperature gages and sensors, pressure gages and sensors, flow meters, and logging devices (e.g. a logging device used to measure the emission of gamma rays from the formation). The assembly **100** may also include power and memory sources to control and communicate with the measurement tools.

The assembly **100** may optionally include the adapter sub **120**. The adapter sub **120** may function as a releasable connection point between the tubing string **110** and the rest of the assembly **100** in case of an emergency that requires a quick removal of the tubing string **110** from the wellbore or another event, such as the assembly **100** getting wedged in the wellbore, to allow removal of the tubing string **110** and to allow a retrieval operation. In addition, the adapter sub **120** may operate as a control valve, such as a check valve, to help control the flow of fluid supplied to the assembly **100** to conduct the fracturing operation.

The unloader **200** is operable to open and close fluid communication between the tubing string **110** and the annulus of the wellbore surrounding the assembly **100**. When the assembly **100** is being located and secured in the wellbore, and when the assembly **100** is being tensioned by pulling on the tubing string **110**, the unloader **200** may be actuated and maintained in a closed position. The unloader **200** may then be actuated into an open position after the assembly **100** is released from being tensioned by the tubing string **110** and/or a downward or push force is applied to the assembly **100** via the tubing string **110**. In the open position, the unloader **200** allows equalization of the pressure above and below the packer **400**A to reduce the pressure differential subjected to the packer **400**A during unsetting of the packer, as well as equalize the pressure internal and external to the assembly **100**. This pressure equalization helps unset the packer **400**A from the wellbore, so that the assembly **100** may be moved in the wellbore without damaging the packer **400**A for subsequent sealing. An exemplary unloader is described in U.S. Patent Application Publication No. 2010/0243254, which description is incorporated herein by reference, including FIGS. **2**A and **2**B and paragraphs [0042] to [0051]. In must be noted that the inclusion of the unloader **200** in the assembly **100** is optional when the packers **400** include a pressure balanced inner mandrel, as described below. An exemplary unloader **200** is disclosed in FIGS. **7**A and **7**B described below.

FIG. **2** illustrates the injection port **300** according to one embodiment of the invention. The injection port **300** allows fluid communication between the assembly **100** and the annulus surrounding the assembly **100** within the wellbore. The injection port **300** includes a cylindrical body **305** having a bore **310** disposed through the body **305**. The inner diameter of an upper end **320** of the body **305** may be connected to the packer **400**, the spacer pipe **130**, and/or other downhole tool that may be included in the assembly **100**. The outer diameter of a lower end **350** of the body **305** may be connected to the packer **400**, the spacer pipe **130**, and/or other downhole tool that may be included in the assembly **100**. The bore **310** of the body **305** may include a restriction section **330** for increasing the flow rate of fluid introduced through the bore **310** of the injection port **300** prior to communication with a port **340** for injection into the annulus surrounding the injection port **300** during a fracturing operation. The bore **310** and the port **340** may be protected with an erosion resistant material such as tungsten carbide. Alternatively, the entire injection port **300** may be formed from an erosion resistant material such as tungsten carbide. In one embodiment, the injection port **300** may include removable tungsten carbide inserts located within the port **340**. In one embodiment, the injection port **300** may include a plurality of ports **340**.

FIG. **3**A illustrates the packer **400** in an unset position according to one embodiment of the invention. The following description of the packer **400** relates to both the packer **400**A and **400**B as shown in FIG. **1**. The packers **400**A and **400**B are substantially similar in operation and are positioned in tandem within the assembly **100** so that they may be simultaneously actuated, or alternatively, one packer may be set and/or unset prior to the other packer. The packers **400**A and **400**B may be configured as part of the assembly **100** to be selectively actuated by an upward or pull force that induces tension in the assembly **100**, via the tubing string **110** for example. The packers **400**A and **400**B are operable, for example, to straddle or sealingly isolate an area of interest in a formation for conducting a fracturing operation to recover hydrocarbons from the formation.

The packer **400** includes a top sub **410**, an inner mandrel **420**, an upper housing **430**, a spring mandrel **440**, a lower housing **450**, a packing element **460**, a latch sub **470**, and a bottom sub **480**. The top sub **410** includes a cylindrical body having a bore disposed through the body. The upper end of the top sub **410** may be configured to connect to the unloader **200** or other downhole tool of the assembly **100**. The lower end of the top sub **410** is coupled to the upper end of the upper housing **430**. The top sub **410** and upper housing **430** interface may be secured together using, for example, a set screw **413**. The inner diameter of the top sub **410** is configured to receive the upper end of the inner mandrel **420**.

The inner mandrel **420** is movably coupled to the top sub **410** and the upper housing **430**. The inner mandrel **420** extends from the top sub **410** to the bottom sub **480**. The inner mandrel **420** has an upper end coupled to an inner recess of the top sub **410**. A seal **416**, such as an o-ring is disposed between the top sub **410** and the inner mandrel **420**. A flange **422** on an outer surface of the inner mandrel **420** is configured to abut the lower end of the top sub **410** and to contact the upper housing **430**. A seal **412**, such as an o-ring, may be provided between the upper housing **430** and inner mandrel **420** interface. A fluid channel **423** is provided in the top sub **410** to supply fluid from the annulus into a space formed between the lower end of the top sub **410** and the flange **422**, when the inner mandrel **420** is moved away from the top sub **410**. In one exemplary embodiment, fluid from the annulus may flow through a clearance **424** defined by the interface between the upper end of the upper housing **430** and the top sub **410** before entering the fluid channel **423**. The size of the clearance **424** may be controlled such that it may act as a debris barrier. For example, the size of the clearance **424** may be set to be smaller than the size of proppant (e.g., 20/40 proppant) used in a fracturing application.

The upper housing **430** includes a cylindrical body having a bore therethrough and surrounds the upper portion of the inner mandrel **420**. A biasing member **425** is disposed in a chamber **426** between the upper housing **430** and the inner mandrel **420**. The biasing member **425** may be a spring that abuts the flange **422** on the outer diameter of the upper end of the inner mandrel **420** at one end and abuts the upper end of a retainer **435** at the other end, thereby biasing the inner mandrel **420** against the bottom end of the top sub **410**. The biasing member **425** may be used to facilitate unsetting of the packing element **460**. The retainer **435** includes a cylindrical body and is disposed between the upper housing **430** and the inner mandrel **420**. The retainer **435** is coupled to the upper housing **430** by a set screw **431**. Seals **436**, **437** may be positioned at the inner and outer surfaces of the retainer **435**. Seals **436**, **437**, and **412** isolate the chamber **426** from fluid communication. In an alternative embodiment, the retainer **435** may be integral with the upper housing **430** in the form of a shoulder, for example, on the upper housing **430** against which the biasing member **425** abuts. The lower end of the upper housing **430** is coupled to the spring mandrel **440**. The inner diameter of the lower end of the upper housing **430** may be coupled to the outer diameter of the upper end of the spring mandrel **440** such that the upper end of the spring mandrel abuts the retainer **435**.

One or more ports **427** are formed in the inner mandrel **420** for fluid communication between the chamber **426** and the bore of the inner mandrel **420**. Pressure in the tubing may enter the chamber **426** and act on the flange **422**, thereby urging the inner mandrel **420** toward the top sub **410**. The pressure in the tubing also acts on the upper end of the inner mandrel **420**, thereby urging the inner mandrel **420** away from the top sub **410**. In one embodiment, the inner mandrel **420** is configured to be pressure balanced against movement by the pressure in the tubing. In this respect, the inner mandrel **420** is configured such that the effective piston area ("Ap**2**" in FIG. **3**B) of the flange **422** is equivalent to the effective piston area ("Ap**1**" in FIG. **3**B) at the upper end of the inner mandrel **420**. Because the opposing piston areas are equivalent, the net force acting on the inner mandrel due to the pressure in the tubing is zero. In this manner, pressure in the tubing would not negatively affect release of the packer **400** or impart additional force into the packing element or system of components retaining the pack-off force.

In one embodiment, an optional debris barrier **429** may be disposed in the chamber and over the one or more ports **427**. The debris barrier **429** may be an annular body positioned between the flange **422** and the biasing member **425**. The debris barrier **429** is configured such that the clearance at the interface between the ports **427** and the debris barrier **429** is controlled such that the interface may act as a barrier against proppant or other debris.

The spring mandrel **440** includes a cylindrical body having a bore disposed through the body, in which the inner mandrel **420** is provided. The lower end of the spring mandrel **440** is coupled to the latch sub **470** to facilitate actuation of the packing element **460**. An inner shoulder of the latch sub **470** abuts an edge of the spring mandrel **440**. The spring mandrel **440** includes longitudinal slots disposed on its outer diameter for receiving a connection member **445** that also facilitates actuation of the packing element **460**. The connection member **445** is disposed on and coupled to the inner mandrel **420**, and is surrounded by and further coupled to the lower housing **450**. The connection member **445** may include a recess on its outer diameter for receiving a set screw disposed through the body of the lower housing **450** to axially fix the lower housing **450** relative to the inner mandrel **420**. The lower housing **450** includes a cylindrical body having a bore disposed through the body, through which the inner mandrel **420** is provided. Also, the lower end of the lower housing **450** surrounds a portion of the spring mandrel **440** such that a shoulder formed on the inner diameter of the lower housing **450** abuts a shoulder formed on the outer diameter of the spring mandrel **440**. A port **443** is formed in the lower housing **450** to supply fluid to the area between the lower housing **450** and the spring mandrel **440**. A cap **444** may be placed over the port **443** to act as a barrier against debris. The clearance at the interface between the port **443** and the cap **444** is controlled such that the interface may act as a barrier against proppant or other debris. The upper end of the lower housing **450** includes an extension member **452** which extends over a portion of the upper housing **430**. The clearance at the interface between the extension member **452** and the upper housing **430** is controlled such that the interface may act as a barrier against proppant or other debris.

As stated above, the lower end of the spring mandrel **440** may be connected to the latch sub **470**, which includes a plurality of latching fingers, such as collets, that engage the outer diameter of the bottom sub **480**. The packing element **460** may include an elastomer that is disposed around the spring mandrel **440** and between an upper and lower gage **455**A and **455**B. The gages **455**A and **455**B are connected to the outer diameters of the lower housing **450** and the latch sub **470**, respectively, and include radially inward projecting ends that engage the ends of the packing element **460** to actuate the packing element **460**. The latch sub **470** and inner mandrel **420** interface may also include a seal **414**, such as an o-ring.

The bottom sub **480** includes a cylindrical body having a bore disposed through the body and is coupled to the lower end of the inner mandrel **420**. The bottom sub **480** and inner mandrel **420** interface may be secured together using, for example, a set screw. The bottom sub **480** and inner mandrel **420** interface may also include a seal **417**, such as an o-ring. A recessed portion on the outer diameter of the bottom sub **480** is adapted for receiving the latching fingers of the latch sub **470** to prevent premature actuation of the packing element **460**. The lower end of the bottom sub **480** may be configured to be coupled to the spacer pipe **140**, the anchor **500**, or other downhole tool that may be included in the assembly **100**.

FIG. **3**B illustrates the packer **400** in a set position according to one embodiment of the invention. An upward or pull force applied to the assembly **100** causes the top sub **410**, the upper housing **430**, the retainer **435**, the spring mandrel **440**, and the latch sub **470** to move axially relative to the inner mandrel **420**, the lower housing **450**, and the bottom sub **480**. Particularly, the upward force separates the top sub **410** from the inner mandrel **420**, thereby compressing the biasing member **425** between the flange **422** on the inner mandrel **420** and the retainer **435**. The spring mandrel **440** also separates from the lower housing **450**, thereby axially moving along the outer diameter of the inner mandrel **420** and pulling on the latch sub **470**. Upon the upward or pull force applied to the top sub **410**, via the tubing string **110** for example, the latching fingers of the latch sub **470** disengage from the bottom sub **480** to actuate the packing element **460**. The latch sub **470** and thus the lower gage **455**B are axially moved toward the stationary lower housing **450** and upper gage **455**A to actuate the packing element **460** disposed therebetween. The lower housing **450** is axially fixed by the anchor **500** (as will be described below) via the connection member **445**, inner mandrel **420**, and bottom sub **480**. The packing element **460** is actuated into sealing engagement with the surrounding surface, which may be the wellbore for example. Relative movement between the components of the packer **400** causes fluid to be drawn in from the annulus to fill the increased space between the top sub **410** and the flange **422** via the fluid channel **423**, the increased space between the upper end of the lower housing **450** and the spring mandrel **440** via the interface between the extension member **452** and the spring mandrel **440**, and the increased space between the lower end of the lower housing **450** and the spring mandrel **440** via the port **443**. Debris is substantially prevented from entering the spaces at the point of entry at each of the respective locations.

Once the packer **400** is set, fluid pressure that is introduced into the assembly **100** for the fracturing operation may act on the upper end of the inner mandrel **420** to urge it toward the packing element **460**, as shown by the downward force arrows. However, the same fluid pressure is present in the chamber **426** via the ports **427** in the inner mandrel **420**. The fluid pressure acts on the flange **422** (as shown by the upward force arrows) to oppose the downward force, thereby resulting in no net force on the inner mandrel **420** from the fluid pressure. In this respect, the inner mandrel **420** is pressure balanced against movement from the fluid pressure. In this manner, fluid pressure in the assembly **100** does not inhibit the release of the packer **400** or impart additional force into the packing element or system of components retaining the pack-off force.

By releasing the tension in the assembly **100** and/or pushing on the tubing string **110**, the top sub **410** and thus the latch sub **470** may be retracted, with further assistance from the biasing member **425**, relative to the inner mandrel **420** to unset the packing element **460**.

Embodiments of the packer **400** may be used in the "up" or "down" vertical orientation. In FIGS. **3**A and **3**B, the packer **400** is shown in the "up" orientation, with the left side of the page being the top of the packer). However, the packer **400** may also be used in the "down" orientation, wherein orientation of the packer **400** is upside-down relative to FIGS. **3**A and **3**B. When used in a multiple packer assembly, one or more of the packers may be in the down orientation. For example, in a two packer, straddle type assembly, potential orientations of the packers **400**A, **400**B include (1) both packers in the "up" orientation; (2) packer **400**A "up" and packer **400**B "down" orientation; (3) packer **400**A "down" and packer **400**B "up" orientation; and (4) both packers down orientation. It is to be noted that because the inner mandrel **420** is pressure balanced, the fluid pressure in the packer **400** does not affect release of the packer **400** when positioned in the down orientation. In the packer **400**A "up" and packer **400**B "down" orientation wherein the latch sub **470** of the "down" packer **400**B is located between the packing elements **460**, fluid pressure in the annulus acting on the packing element **460** is transmitted through the lower housing **450**, the connection member **445**, and the inner mandrel **420**. In this respect, the fluid pressure does not add to the load on the spring mandrel **420** when the packers are used in this orientation. As noted above, when both packers **400** include pressure balanced inner mandrels, inclusion of the unloader **200** in the assembly **100** becomes optional. In another embodiment, one of the packers may be selected from other mechanically set or hydraulic set packers. For example, a hydraulic set packer may be paired with a packer **400** having a pressure balanced inner mandrel. The packer **400** may be positioned in either the "up" or "down" orientation. An exemplary hydraulic set packer is disclosed in U.S. Pat. No. 6,253,856 to Ingram, et al. which patent is incorporate herein by reference in its entirety. An exemplary mechanically set packer is disclosed in U.S. Patent Application Publication No. 2010/0243254, which application is incorporated herein by reference, including FIGS. **3**A and **3**B and paragraphs [0052] to [0058]. An exemplary packer suitable for pairing with packer **400** is disclosed in FIGS. **6**A and **6**B described below.

During operation, the packers **400**A, **400**B may be simultaneously actuated or in sequence. For example, to actuate the packers **400**A, **400**B in sequence, the upper packer **400**A may be configured with a biasing member **425** that has a higher biasing force than the biasing member of the lower packer **400**B. In this respect, the lower packer **400**B may be actuated first. In another embodiment, the latching fingers of the latching sub **470** may be configured to require a higher release force to disengage from the bottom sub **480**, such that the lower packer **400**B would actuated first. In one example, the outer diameter of the bottom sub **480** and/or the latching fingers are designed with different engagement angles in order to adjust the release force. If a hydraulic actuated packer is paired with a tension set packer **400**, then the tension set packer **400** may be actuated first if it is located below the hydraulic packer. If the tension set packer **400** is located above the hydraulic set packer, then either packer may be actuated first.

FIG. **4**A illustrates the anchor **500** in an un-actuated position according to one embodiment of the invention. The anchor **500** includes a top sub **510**, an inner mandrel **520**, first retainer **530**, a friction section **540** (such as a drag spring or block), a second retainer **545**, an inner sleeve **550**, an outer sleeve **560**, a slip **570**, a cone **580**, and a bottom sub **590**. The top sub **510** includes a cylindrical body having a bore disposed through the body. The upper end of the top sub **510** may be coupled to the packer **400** or other downhole tool that may be included in the assembly **100**. The lower end of the top sub **510** may be coupled to the inner mandrel **520**. A seal **511**, such as an o-ring, may be provided between the top sub **510**/inner mandrel **520** interface.

The inner mandrel **520** includes a cylindrical body having a bore disposed through the body and slots **525** longitudinally disposed along the outer diameter of the inner mandrel **520**. In one embodiment, the inner mandrel **520** may include a pair of slots **525**. The slots **525** may be symmetrically located on the outer diameter of the inner mandrel **520**. As will be described below, the slots **525** facilitate setting and unsetting of the anchor **500**.

The friction section **540** includes a plurality of members **541** radially disposed around the inner mandrel **520** that are secured to the inner mandrel **520** at their ends with the first retainer **530** and the second retainer **545** such that the center portions of the members project outwardly from the inner mandrel **520**. The friction section **540** allows axial movement of the inner mandrel **520** relative to the members **541**, the outer sleeve **560**, and the slip **570** by generating friction between the members **541** and the surrounding wellbore as the friction section **540** engages and moves along the surrounding wellbore. The first retainer **530** includes a cylindrical body having a bore disposed through the body, through which the inner mandrel **520** is provided. The upper end of the members **541** may include openings that engage raised portions on the outer diameter of the first retainer **530**. A cover **535** may be coupled around the first retainer **530** to prevent disengagement of the raised portions on the outer diameter of the first retainer **530** and the openings in the upper end of the members **541**. The cover **535** includes a cylindrical body having a bore disposed through the body, through which the first retainer **530** and the inner mandrel **520** are provided. The cover **535** may be coupled to the first retainer **530**. The first retainer **530** and the cover **535** may be axially movable relative to the inner mandrel **520**.

At the opposite side, the lower end of the members **541** may similarly be coupled to the second retainer **545**. The second retainer **545** includes a cylindrical body having a bore disposed through the body, through which the inner mandrel **520** is provided. The second retainer **545** includes raised portions on its outer diameter for engaging openings disposed through the lower end of the members **541**. The outer sleeve **560** may be coupled around the second retainer **545** to prevent disengagement of the raised portions on the outer diameter of the second retainer **545** and the openings in the lower end of the members **541**. The outer sleeve **560** includes a cylindrical body having a bore disposed through the body, through which the first retainer **530**, the inner sleeve **550**, and the inner mandrel **520** are provided. The upper end of the outer sleeve **560** may be coupled to the second retainer **545**. The second retainer **545** and the outer sleeve **560** may be axially movable relative to the inner mandrel **520**.

The lower end of the outer sleeve **560** may include a shoulder disposed on its inner diameter that engages a shoulder disposed on the outer diameter of the inner mandrel **520** to limit the axial movement between the two components. Coupled to the lower end of the outer diameter of the outer sleeve **560** is the slip **570**. The slip **570** may be coupled to the outer sleeve **560** via a threaded insert **575** that is partially disposed in the body of the outer sleeve **560**. The slip **570** may include a plurality of slip members, such as collets, radially disposed around the slip **570** having teeth disposed on the outer periphery of the ends of the slip members to engage and secure the anchor **500** in the wellbore. The ends of the slip members include a tapered inner diameter for receiving the corresponding tapered outer surface of the cone **580**. Upon engagement between the outer surface of the cone **580** and the inner surface of the slip **570**, the cone **580** projects the slip members outwardly into engagement with the surrounding wellbore to set and secure the anchor **500** in the wellbore. In one embodiment, the wellbore may be lined with casing. In one embodiment, the wellbore may be an open hole and may not include any lining or casing.

The cone **580** includes a cylindrical body having a bore disposed through the body, through which the inner mandrel **520** is provided. The cone **580** has a tapered nose operable to engage the tapered inner surface of the slip **570**. The cone **580** is axially fixed relative to the inner mandrel **520** and abuts the upper end of the bottom sub **590**. The bottom sub **590** includes a cylindrical body having a bore disposed through the body, through which the inner mandrel **520** is partially provided. The upper end of the bottom sub **590** is coupled to the lower end of the inner mandrel **520**. A seal **512**, such as an o-ring, may be provided between the bottom sub **590**/inner mandrel **520** interface. The lower end of the bottom sub **590** may be configured to connect to a variety of other downhole tools that may be included or attached to the assembly **100**.

To set and unset the slip **570** by engagement with the cone **580**, the relative movement between the inner mandrel **520** (and thus the cone **580**) and the outer sleeve **560** (and thus the slip **570**) is controlled with a pair of lugs **555** and a pair of pins **557** that are disposed through the inner sleeve **550** and facilitated with the friction section **540**. The friction section **540** creates a friction interface with the wellbore to allow the inner mandrel **520** to move axially relative to the outer sleeve **560** as the assembly **100** is raised and lowered. The inner sleeve **550** includes a cylindrical body having a bore disposed through that body that is disposed between the upper end of the outer sleeve **560** and the inner mandrel **520**, adjacent the second retainer **545**. The inner sleeve **550** is rotatable relative to the outer sleeve **560** and the inner mandrel **520**, as the inner mandrel **520** is moved in an "up and down" motion relative to the inner sleeve **550** and the outer sleeve **560**. The lugs **555** and the pins **557** are further seated within the slots **525** located on the outer diameter of the inner mandrel **520**.

As illustrated in FIGS. **4**B-**4**D, the slots **525** include a cam portion **527**, along which the pins **557** travel, and a channel portion **529**, through which the lugs **555** may travel to set and release the anchor **500**. When the pins **557** are located within the cam portion **527**, the anchor **500** is prevented from setting. The cam portion **527** includes a plurality of lanes having linear sections and helical sections that are directed into adjacent lanes. The cam portion **527** further includes exits **526** in lanes that communicate and align with channels **528** of the channel portion **529**. As the inner mandrel **520** is pulled and pushed in an "up and down" motion, via the top sub **510** that is coupled to the tubing string **110** through the remainder of the assembly **100**, the pins **557** move along the lanes of the cam portion **527** and are continuously directed into adjacent lanes such that the outer sleeve **550** rotates relative to the inner mandrel **520**. The pins **557** travel along the cam portion **527** until they reach exits **526** and are allowed to exit from the cam portion **527** by an upward or pull force. As the inner mandrel **520** is directed in the "up and down" motion, the lugs **555** may be aligned with and located relative to the pins **557** to engage the outer rims **524** of the cam portion **527** and the channel portion **529** to prevent the pins **557** from contacting the ends of the lanes in the cam portion **527** and protect them from bearing any excessive loads induced by forces applied to the inner mandrel **520**. When the pins **557** reach an exit **526**, the lugs **555** may travel into channels **528**, which keeps the pins **557** in alignment with the exits **526** and allows further axial movement of the inner mandrel **520**. Upon the pins **557** exiting and the lugs **555** traveling within the channels **528** by the upward or pull force, the inner mandrel **520** is permitted to move further axially relative to the outer sleeve **560**, thereby allowing the cone **580** to engage the slip **570** and actuate the slip members into engagement with the wellbore, as illustrated in FIG. **4**E. After the slip **570** is engaged with the wellbore, the assembly **100** is secured in the wellbore as it is held in tension via the tubing string **110**.

To unset the slip **570**, the tension in the assembly **100** is released and/or a downward or push force is applied to the inner mandrel **520**, using the tubing string **110**, thereby reintroducing the pins **557** onto the cam portion **527** via the exits **526** and permitting the cone **580** to retract from engagement with the slip **570** and the slip members to retract from engagement with the wellbore. Once the pins **557** are directed into the cam portion **527**, the pins **557**, the lugs **555**, and the cam portion **527** limit the axial movement between the cone **580** and the slip **570** to prevent setting of the slip **570** as described above. In alternative embodiments, the cam portion **527** may include other configurations that allow the pins **557** to move along the cam portion **527** and to exit/enter the cam portion **527** to set and unset the anchor **100**. After the anchor **500** is released from engagement with the wellbore, the assembly **100** may be relocated to another area of interest or location in the wellbore to conduct another fracturing or other downhole operation following the operation of the assembly **100** described herein.

FIG. **5**A illustrates an embodiment of an anchor assembly **600** in an un-actuated position. The anchor assembly **600** may be used in combination with the embodiments of the assembly **100** described herein. The anchor **600** includes a top sub **610**, an inner mandrel **620**, a first retainer **630**, a friction section **640** (such as a drag spring or block), a second retainer **645**, an unloading sleeve **650**, an outer sleeve **660**, a slip **670**, a cone assembly **680**, and a bottom sub **690**. The top sub **610** includes a cylindrical body having a bore disposed through the body. The upper end of the top sub **610** may be coupled to the packer **400** or other downhole tool that may be included in the assembly **100**. The lower end of the top sub **610** may be coupled to the inner mandrel **620**. A seal **611**, such as an o-ring, may be provided between the top sub **610**/inner mandrel **620** interface.

The inner mandrel **620** includes a cylindrical body having a bore disposed through the body, one or more ports **657**, and slots **625** longitudinally disposed along the outer diameter of the inner mandrel **620**. The ports **657** are operable to facilitate unloading of the pressure in the assembly **100** and to facilitate unsetting of the packer **400** located above the anchor **600** by equalizing the pressure across the packer. In one embodiment, the inner mandrel **620** may include a pair of slots **625**. The slots **625** may be symmetrically located on the outer diameter of the inner mandrel **620**. As described above with respect to FIGS. **5B-5D**, the slots **625** similarly facilitate setting and unsetting of the assembly **600**.

The friction section **640** includes a plurality of members **641** radially disposed around the inner mandrel **620** that are secured to the inner mandrel **620** at their ends with the first retainer **630** and the second retainer **645** such that the center portions of the members project outwardly from the inner mandrel **620**. The friction section **640** allows axial movement of the inner mandrel **620** relative to the members **641**, the sleeves **650** and **660**, and the slip **670** by generating friction between the members **641** and the surrounding wellbore as the friction section **640** engages and moves along the surrounding wellbore. The first retainer **630** includes a cylindrical body having a bore disposed through the body, through which the inner mandrel **620** is provided. The upper end of the members **641** may include openings that engage raised portions on the outer diameter of the first retainer **630**. A cover **635** may be coupled around the first retainer **630** to prevent disengagement of the raised portions on the outer diameter of the first retainer **630** and the openings in the upper end of the members **641**. The cover **635** includes a cylindrical body having a bore disposed through the body, through which the first retainer **630** and the inner mandrel **620** are provided. The cover **635** may be coupled to the first retainer **630**. The first retainer **630** and the cover **635** may be axially movable relative to the inner mandrel **620**.

At the opposite side, the lower end of the members **641** may similarly be coupled to the second retainer **645**. The second retainer **645** includes a cylindrical body having a bore disposed through the body, through which the inner mandrel **520** is provided. The second retainer **645** includes raised portions on its outer diameter for engaging openings disposed through the lower end of the members **641**. The unloading sleeve **650** may be coupled to the second retainer **645** to prevent disengagement of the raised portions on the outer diameter of the second retainer **645** and the openings in the lower end of the members **641**. The unloading sleeve **650** includes a cylindrical body having a bore disposed through the body, through which the first retainer **630** and the inner mandrel **620** are provided. The unloading sleeve **650** also includes one or more ports **655** that communicate with the one or more ports **657** in the inner mandrel **620** when the ports are aligned, generally when the anchor **600** is in the unset position. The ports **655** and **657** provide fluid communication between the assembly **100** and the wellbore surrounding the assembly **100** to relieve pressure internal of the assembly **100** and to help equalize the pressure across the packer **400** located above the anchor **600**. One or more seals **627**, such as o-rings, may be located between the loading sleeve **650**/inner mandrel **620** interface to provide seals above and below the ports **655** and **657**. The upper end of the unloading sleeve **650** may be coupled to the second retainer **645**. The inner mandrel **620** is axially moveable relative to the second retainer **645** and the unloading sleeve **650**.

Coupled to the lower end of the unloading sleeve **650**, is the outer sleeve **660**. The outer sleeve **660** may include a cylindrical body having a bore therethrough, which surrounds the inner mandrel **620** and an inner sleeve **665**. The lower end of the outer sleeve **660** is coupled to the slip **670**. The slip **570** may be coupled to the outer sleeve **660** via a threaded insert **675** that is partially disposed in the body of the outer sleeve **660**. The slip **670** may include a plurality of slip members, such as collets, radially disposed around the slip **670** having teeth disposed on the outer periphery of the ends of the slip members to engage and secure the anchor **600** in the wellbore. The ends of the slip members include a tapered inner diameter for receiving the corresponding tapered outer surface of the cone assembly **680**. Upon engagement between the outer surface of the cone assembly **680** and the inner surface of the slip **670**, the cone assembly **680** projects the slip members outwardly into engagement with the surrounding wellbore to set and secure the anchor **600** in the wellbore. In one embodiment, the wellbore may be lined with casing. In one embodiment, the wellbore may be an open hole, and may not include any lining or casing.

The cone assembly **680** includes an upper portion **681**, a middle portion **682**, a lower portion **683**, and one or more packing elements **685** located adjacent the middle portion **682**. Each of the portions may include cylindrical bodies having a bore disposed through the body, through which the inner mandrel **620** is provided. The upper portion **681** has a tapered nose operable to engage the tapered inner surface of the slip **670**, and an inner shoulder operable to engage a shoulder on the outer diameter of the inner mandrel **620**. The packing elements **685** are located one each side of the middle portion **682**. Each of the portions includes a lip profile at their outer edges that are operable to retain the packing elements **685** therebetween. The lower portion **683** may be axially and shearably fixed relative to the inner mandrel **620** via a retainer **687**. The upper and middle portions **681** and **682** are movable relative to the lower portion **683**, to allow actuation of the packing elements **685**. Upon engagement with the slip **670**, the upper and middle portions **681** and **682** are directed toward the fixed lower portion **683**, thereby compressing the packing elements **685** into engagement with the surrounding wellbore. The packing elements **685** may be formed from an elastomeric material.

The lower portion **683** abuts the upper end of a mandrel **689**, which abuts the bottom sub **690**. The mandrel **689** may include a cylindrical body having a bore therethrough that surrounds the inner mandrel **620**. The mandrel **689** may be operable to help position the cone assembly **680** along the lower end of the anchor **600** and to transfer loads from and provide a reactive force against the cone assembly **680**. The bottom sub **690** includes a cylindrical body having a bore disposed through the body, through which the inner mandrel **620** is partially provided. The upper end of the bottom sub **690** is coupled to the lower end of the inner mandrel **620**. A seal **612**, such as an o-ring, may be provided between the bottom sub **690**/inner mandrel **620** interface. The lower end of the bottom sub **690** may be configured to connect to a variety of other downhole tools that may be included or attached to the assembly **100**.

To set and unset the slip **670**, the relative movement between the inner mandrel **620** (and thus the cone **680**) and the outer sleeve **660** (and thus the slip **670**) is controlled with a pair of lugs **669** and a pair of pins **667** that are disposed through the inner sleeve **665** and facilitated with the friction section **640**. The friction section **640** creates a friction interface with the wellbore to allow the inner mandrel **620** to move axially relative to the outer sleeve **660** as the assembly **100** is raised and lowered on the tubing string **110**. The inner sleeve **665** includes a cylindrical body having a bore disposed through the body that is disposed between the outer sleeve **660** and the loading sleeve **650**. The inner sleeve **665** is rotatable relative to the outer sleeve **660** and the inner mandrel **620**, as the inner mandrel **620** is moved in an “up and down” motion relative to the inner sleeve **665** and the outer sleeve **660** by the use of lugs **669** and pins **667** that are seated within the slots **625** located on the outer diameter of the inner mandrel **620**. The lugs **669** and pins **667** are actuated along the slots **625** as described above with the operation of the anchor **500**, as shown in FIGS. **4**B-**4**D. Upon actuation of the lugs **669**/pins **667**/slots **625**/outer sleeve **665** interface, the cone assembly **680** is directed into engagement with the slip **670**, via the inner mandrel **620** and the top sub **610**, by an upward or pull force on the tubing string **110** of the assembly **100**.

FIG. **5**B illustrates the initial engagement of the slip **670** and the cone assembly **680**. The slip **670** is projected into engagement with the surrounding wellbore and the packing elements **685** are compressed within the cone assembly **680**. Further tensioning of the anchor **600** forces the cone assembly **680** to project the slips into a set position within the wellbore and allows the packing elements to sealingly engage the wellbore, as shown in FIG. **5**C. Also shown in FIGS. **5**B and **5**C are the ports **655** and **657** sealingly isolated from each other. When the anchor **600** is in the set position, fluid communication is closed between the throughbore of the anchor **600** and the surrounding wellbore. This allows a fracturing operation to be conducted without a loss of pressure through the anchor **600** using the embodiments described above.

To unset the slip **670** and the packing elements **685**, the tension in the assembly **100** is released and/or a downward or push force is applied to the inner mandrel **520**, using the tubing string **110**, thereby permitting the cone assembly **680** to retract from engagement with the slip **670**. The slip members and the packing elements retract from engagement with the wellbore, and the packing elements **685** retract the middle and upper portions of the cone assembly **680** from the lower portion. When the anchor **600** is in an unset position, the ports **655** and **657** may open fluid communication between the throughbore of the anchor **600** and the surrounding wellbore to equalize the pressure differential therebetween, as well as across the packer **400** located above the anchor **600**. After the anchor **600** is released from engagement with the wellbore, the assembly **100** may be relocated to another area of interest or location in the wellbore to conduct another fracturing or other downhole operation following the operation of the assembly **100** described herein.

FIG. **6**A illustrates a packer **700** in an unset position according to one embodiment of the invention. The packer **700** may be configured as part of the assembly **100** to be selectively actuated by an upward or pull force that induces tension in the assembly **100**, via the tubing string **110** for example. One or more of the packers **700** may be used in combination with packer **400**, for example, to straddle or sealingly isolate an area of interest in a formation for conducting a fracturing operation to recover hydrocarbons from the formation.

The packer **700** includes a top sub **710**, an inner mandrel **720**, an upper housing **730**, a spring mandrel **740**, a lower housing **750**, a packing element **760**, a latch sub **770**, and a bottom sub **780**. The top sub **710** includes a cylindrical body having a bore disposed through the body. The inner diameter of the upper end of the top sub **710** may be configured to connect to the unloader **200** or other downhole tool of the assembly **100**. The lower end of the top sub **710** is coupled to the upper end of the upper housing **730**. The top sub **710**/upper housing **730** interface may be secured together using, for example, a set screw. The top sub **710**/upper housing **730** interface may also include a seal **711**, such as an o-ring.

The upper housing **730** includes a cylindrical body having a bore disposed through the body, through which the inner mandrel **720** is provided. The upper housing **730** surrounds the upper end of the inner mandrel **720** such that the bottom end of the top sub **710** abuts the top end of the inner mandrel **720**. A seal **712**, such as an o-ring, may be provided between the upper housing **730**/inner mandrel **720** interface. The upper housing **730** encloses a biasing member **725** that surrounds the inner mandrel **720**. The biasing member **725** may include a spring that abuts a shoulder formed on the outer diameter of the upper end of the inner mandrel **720** at one end and abuts the upper end of a retainer **735** at the other end, thereby biasing the inner mandrel **720** against the bottom end of the top sub **710**. The biasing member **725** may be used to facilitate unsetting of the packing element **760**. The retainer **735** includes a cylindrical body having a bore disposed through the body, through which the inner mandrel **720** is provided. The retainer **735** is surrounded by and coupled to the upper housing **730** by a set screw **731**. In an alternative embodiment, the retainer **735** may be integral with the upper housing **730** in the form of a shoulder, for example, on the upper housing **700** against which the biasing member **725** abuts. The lower end of the upper housing **730** is coupled to the spring mandrel **740**. The inner diameter of the lower end of the upper housing **730** may be coupled to the outer diameter of the upper end of the spring mandrel **740** such that the upper end of the spring mandrel abuts the retainer **735**.

The spring mandrel **740** includes a cylindrical body having a bore disposed through the body, in which the inner mandrel **720** is provided. The lower end of the spring mandrel **740** is coupled to the latch sub **770** to facilitate actuation of the packing element **760**. An inner shoulder of the latch sub **770** abuts an edge of the spring mandrel **740**. The spring mandrel **740** includes longitudinal slots disposed on its outer diameter for receiving a member **745** that also facilitates actuation of the packing element **760**. The member **745** is disposed on and coupled to the inner mandrel **720**, and is surrounded by and further coupled to the lower housing **750**. The member **745** may include a recess on its outer diameter for receiving a set screw disposed through the body of the lower housing **750** to axially fix the lower housing **750** relative to the inner mandrel **720**. The lower housing **750** includes a cylindrical body having a bore disposed through the body, through which the inner mandrel **720** is provided. Also, the lower end of the lower housing **750** surrounds a portion of the spring mandrel **740** such that a shoulder formed on the inner diameter of the lower housing **750** abuts a shoulder formed on the outer diameter of the spring mandrel **740**.

As stated above, the lower end of the spring mandrel **740** may be connected to the latch sub **770**, which includes a plurality of latching fingers, such as collets, that engage the outer diameter of the bottom sub **780**. The packing element **760** may include an elastomer that is disposed around the spring mandrel **740** and between an upper and lower gage **755**A and **755**B. The gages **755**A and **755**B are connected to the outer diameters of the lower housing **750** and the latch sub **770**, respectively, and include radially inward projecting ends that engage the ends of the packing element **760** to actuate the packing element **760**. The latch sub **770**/inner mandrel **720** interface may also include a seal **714**, such as an o-ring.

The bottom sub **780** includes a cylindrical body having a bore disposed through the body and is coupled to the lower end of the inner mandrel **720**. The bottom sub **780**/inner mandrel **720** interface may be secured together using, for example, a set screw. The bottom sub **780**/inner mandrel **720** interface may also include a seal **713**, such as an o-ring. A recessed portion on the outer diameter of the bottom sub **780** is adapted for receiving the latching fingers of the latch sub **770** to prevent premature actuation of the packing element **760**. The lower end of the bottom sub **780** may be configured to be coupled to the spacer pipe **130**, the anchor **500**, or other downhole tool that may be included in the assembly **100**.

FIG. **6**B illustrates the packer **700** in a set position according to one embodiment of the invention. The top sub **710**, the upper housing **730**, the retainer **735**, the spring mandrel **740**, and the latch sub **770** are axially movable relative to the inner mandrel **720**, the lower housing **750**, and the bottom sub **780**. As the assembly **100** is tensioned, the top sub **710** is separated from the inner mandrel **720**, thereby compressing the biasing member **725** between the shoulder on the inner mandrel **720** and the retainer **735**, and the spring mandrel **740** is separated from the lower housing **750**, thereby axially moving along the outer diameter of the inner mandrel **720** and pulling on the latch sub **770**. Upon the upward or pull force applied to the top sub **710**, via the tubing string **110** for example, the latching fingers of the latch sub **770** disengage from the bottom sub **780** to actuate the packing element **760**. The latch sub **770** and thus the lower gage **755**B are axially moved toward the stationary lower housing **750** and upper gage **755**A to actuate the packing element **760** disposed therebetween. The lower housing **750** is axially fixed by the anchor **500** (as will be described below) via the member **745**, inner mandrel **720**, and bottom sub **780**. The packing element **760** is actuated into sealing engagement with the surrounding surface, which may be the wellbore for example. Once the packer **700** is set, fluid pressure that is introduced into the assembly **100** for the fracturing operation may boost the sealing effect of the packing element **760** by telescoping apart the top sub **710** and the inner mandrel **720** as the pressure acts on the bottom end of the top sub **710** and the top end of the inner mandrel **720**. The bottom sub **780** may include a piston shoulder on its inner diameter to counter balance the boost enacted upon the packing element **360** to control setting and unsetting of the packing element **760**. By releasing the tension in the assembly **100** and/or pushing on the tubing string **110**, the top sub **710** and thus the latch sub **770** may be retracted, with further assistance from the biasing member **725**, relative to the inner mandrel **720** to unset the packing element **360**.

FIG. **7**A illustrates the unloader **200** according to one embodiment of the invention. The unloader **200** is operable to help equalize the pressure above and below the packer **400**A, **700** to reduce the pressure differential subjected to the packer **400**A, **700** during unsetting of the packer, as well as equalize the pressure internal and external to the assembly **100**. This pressure equalization helps unset the packer **400**A, **700** from the wellbore, so that the assembly **100** may be moved in the wellbore without damaging the packer **400**A, **700** for subsequent sealing. The unloader **200** is operable to open and close fluid communication between the tubing string **110** and the annulus of the wellbore surrounding the assembly **100**. When the assembly **100** is being located and secured in the wellbore, and when the assembly **100** is being tensioned by pulling on the tubing string **110**, the unloader **200** may be actuated and maintained in a closed position. The unloader **200** may then be actuated into an open position after the assembly **100** is released from being tensioned by the tubing string **110** and/or a downward or push force is applied to the assembly **100** via the tubing string **110**.

The unloader **200** includes a top sub **210**, an inner mandrel **220**, an upper housing **230**, a coupler **240**, a biasing member **250**, and a lower housing **260**. The top sub **210** comprises a cylindrical body having a bore disposed through the body. In one embodiment, the upper end of the top sub **210** may be coupled to the adapter sub **120**. In one embodiment, the upper end of the top sub **210** is configured to couple the unloader **200** to a tubing string or other downhole tool positioned above the unloader **200**. The lower end of the top sub **210** is coupled to the upper end of the inner mandrel **220**. The inner diameter of the top sub **210** is connected to the outer diameter of the inner mandrel **220**, such as by a thread, and a seal **211**, such as an o-ring, may be used to seal the top sub **210**/inner mandrel **220** interface. The top sub **210** is connected to the inner mandrel **220** such that the components are in fluid communication.

The inner mandrel **220** comprises a cylindrical body having a bore disposed through the body. The inner mandrel **220** further includes a first opening **223**, a second opening **225**, a third opening **227**, and a piston **225**. The openings **223**, **225**, **227** may vary in number, may be symmetrically located about the body, and may include laser cut slots disposed through the walls of the body to filter sand, particulates, or other debris from exiting or entering the bore of the inner mandrel **220**. The first and second openings **223**, **225** and the piston **225** are surrounded by the upper housing **230**. The third opening **227** is surrounded by the lower housing **260**. The coupler **240** also surrounds the body of the inner mandrel **220** and is disposed between the upper and lower housings **230** and **260** such that the upper housing is coupled to the upper end of the coupler **240** and the lower housing is coupled to the lower end of the coupler **240**, thereby enclosing the lower end of the inner mandrel **220**. The inner diameters of the housings **230** and **260** may be threadedly coupled to the outer diameter of the coupler **240**. The inner mandrel **220** is axially movable relative to the housings **230** and **260** and the coupler **240**.

The upper housing **230** includes a cylindrical body having a bore disposed through the body, through which the inner mandrel **220** is provided. The upper housing **230** includes an opening **235** disposed through the body of the housing that establishes fluid communication between the bore of the inner mandrel **220** and the annulus surrounding the unloader **200** via the first opening **223** of the inner mandrel **220**. The opening **235** may comprise a nozzle to controllably inject fluid into the annulus surrounding the unloader **200**. When the unloader **200** is in the closed position, the first opening **223** of the inner mandrel **220** is sealingly isolated from the opening **235** of the upper housing **230**, and when the unloader **200** is in the open position, the first opening **223** of the inner mandrel **220** is in fluid communication with the opening **235** of the upper housing **230**. The unloader is actuated into the closed and open positions by relative axial movement between the inner mandrel **220** and the upper housing **230**. A plurality of seals **212**, **213**, **214**, and **215**, such as o-rings, may be used to seal the inner mandrel **220**/upper housing **230** interfaces, above and below the opening **235** of the upper housing **230**.

The lower end of the upper housing **230** includes an enlarged inner diameter such that the piston **229** of the inner mandrel **220** is sealingly engaged with the inner diameter of the housing **230** and engages a shoulder formed on the inner diameter of the housing **230**. A seal **216**, such as an o-ring, may be used to seal the piston **229**/upper housing **230** interface. The piston **229** includes an enlarged shoulder disposed on the outer diameter of the inner mandrel **220**. In the closed position, piston **229** of the inner mandrel **220** abuts the shoulder formed on the inner diameter of the upper housing **230**. The second opening **225** of the inner mandrel **220** is located adjacent the piston **229** of the inner mandrel **220** to allow fluid pressure to be communicated from the bore of the inner mandrel **220** to the piston **229**. The lower end of the upper housing **230** includes a port **233** that establishes fluid communication between the annulus surrounding the unloader **200** and a chamber formed between the upper housing **230** and the inner mandrel **220** that is disposed adjacent the piston **229** of the inner mandrel **220**. The port **233** may be used to introduce pressure back into the unloader **200** to reduce the pressure differential across the piston **229**. Finally, the lower end of the upper housing **230** is coupled to the upper end of the coupler **240**.

The coupler **240** includes a cylindrical body having a bore disposed through the body, through which the inner mandrel **220** is provided. The coupler **240** includes a shoulder disposed on its outer diameter against which the ends of the housings **230** and **260** engage. Seals **217** and **218**, such as o-rings, may be positioned between the upper housing **230**/lower housing **260**/coupler **240**/inner mandrel **220** interfaces. A set screw **243** is disposed through the body of the coupler **240** and engages a recess in the outer diameter of the inner mandrel **220** such that the inner mandrel is axially movable relative to the coupler **240** but is rotationally fixed relative to the coupler **240** and the upper and lower housings **230** and **260**. The piston **229** of the inner mandrel **220** may engage the upper end of the coupler **240** when the unloader **200** is in a fully open position. Finally, the upper end of the lower housing **260** is coupled to the lower end of the coupler **240**.

The lower housing **260** includes a cylindrical body having a bore disposed through the body, through which the inner mandrel **220** is provided. The lower housing **260** also includes an enlarged inner diameter at its upper end, forming a chamber between the lower housing **260** and the inner mandrel **220** in which the biasing member **250** is disposed. The third opening **227** of the inner mandrel **220** is in fluid communication with the chamber. The lower end of the inner mandrel **220** sealingly engages a reduced inner diameter at the lower end of the lower housing **260** such that the bore of the inner mandrel **220** exits into the bore of the lower housing **260**. A wiper ring **221** may be used at the lower end of the inner mandrel **220** between the inner mandrel **220**/lower housing **260** interface to prevent and remove debris that flows through the unloader **200**. The lower end of the lower housing **260** may be configured to threadedly connect to the packer **400**A, **700** or other downhole tool of the assembly **100**.

The biasing member **250** may include a spring that abuts a shoulder formed on the inner diameter of the lower housing **260** at one end and abuts a retainer **253** at the other end. The retainer **253** includes a cylindrical body that surrounds the inner mandrel **220** and is operable to retain the biasing member **250**. A ring **255** that is partially disposed in the body of the inner mandrel **220** is operable to retain the retainer **253** and transmit the biasing force of the biasing member **250** against the retainer **253** to the inner mandrel **220**. The ring **255** includes a cylindrical body that surrounds the inner mandrel **220**, such as a split ring, that can be enclosed around the inner mandrel **220**. In an alternative embodiment, the ring **255** and the retainer **253** may be integral with the inner mandrel **220** in the form of a shoulder, for example, on the inner mandrel **220** against which the biasing member **250** abuts. The biasing member **250** biases the retainer **253** against the lower end of the coupler **240**, which biases the inner mandrel **220** in the closed position via the ring **255**. In addition, tensioning of the tubing string **110** may also pull on the top sub **210** and thus the inner mandrel **220** to set and maintain the unloader **200** in the closed position.

FIG. **7**B illustrates the unloader **200** in the open position according to one embodiment of the invention. A downward or push force may be applied to the top sub **210** via the tubing string **110**, thereby axially moving the inner mandrel **220** relative to the upper and lower housings **230** and **260** and the coupler **240** to position the first opening **223** of the inner mandrel **220** in fluid communication with the opening **235** of the upper housing. A fluid may then be injected into the annulus surrounding the unloader **200** to increase the pressure in the annulus, which may help equalize the pressure above and below the packer **400**A, **700** and reduce the pressure differential across packer **400**A, **700** to assist unsetting of the packer **400**A, **700**. At the same time, fluid pressure may be introduced onto the piston **229** of the inner mandrel **220** via the second opening **225** to help control actuation of the unloader **200** into the open position. As stated above, the port **233** may be used to introduce pressure back into the unloader **200** to reduce the pressure differential across the piston **229**. Simultaneously, the ring **255**, which is engaged with the inner mandrel **220**, forces the retainer **253** against the biasing member **250**. Fluid pressure is also introduced into the chamber between the lower housing **260** and the inner mandrel **220** via the third opening **227** of the inner mandrel **220**, which may further facilitate actuation of the unloader **200** into the open position. The bottom end of the inner mandrel **220** may act as a piston surface to counter balance the piston **229** of the inner mandrel **220** which further enables controlled actuation of the unloader **200**.

In one embodiment, a second unloader **200** may be disposed above the lower packer **400**B, **700** and below the injection port **300** to facilitate unsetting of the packer **400**B, **700**. A plug, such as a solid blank pipe having no throughbore or a closed end of the injection port **300** or the second unloader **200**, is located between the throughbores of the injection port **300** and the second unloader **200** so that flow through the assembly **100** is injected out through the injection port **300**. Upon setting of the assembly **100**, the second unloader is actuated into the closed position as described above, and a fracturing operation may be conducted in the area of interest (through the injection port **300**) without any loss of pressure or fluid through the second unloader **200**. After the fracturing operation is complete, the assembly **100** may be unset and the second unloader **200** may be positioned into the open position as described above, thereby opening fluid communication between the throughbore of the second unloader **200** and the wellbore surrounding the second unloader **200**. The pressure in the wellbore may be directed from the area of interest in the formation, into the lower end of the assembly **100** via the second unloader **200**, and then back out into the wellbore to facilitate unsetting of the packer **400**B, **700**. In one embodiment, an open port may be located below the packer **400**B, **700** to allow the pressure from the annulus above the packer **400**B, **700** to be directed to the annulus below the packer **400**B, **700** via the second unloader **200** to equalize the pressure across the packer **400**B, **700**. In one embodiment, an anchor (further described herein) having a throughbore in communication with the wellbore may be located below the packer **400**B, **700** to allow the pressure from the annulus above the packer **400**B, **700** to be directed to the annulus below the packer **400**B, **700** via the second unloader **200** to equalize the pressure across the packer **400**B, **700**.

In one embodiment, an assembly **100** may include a packer **400**, an injection port **300** coupled to and disposed below the packer **400**, an anchor **600** coupled to and disposed below the injection port **300**, and a plug, such as a solid blank pipe having no throughbore or a closed end of the injection port **300** or the anchor **600**, disposed between the throughbores of the injection port **300** and the anchor **600** so that flow through the assembly **100** is injected out through the injection port **300**. The assembly **100** may be coupled to a tubing string to operate the assembly **100** as described above. When the assembly **100** actuated by applying a mechanical force (such as an upward or pull force) to the tubing string, the packer **400** and the anchor **600** are actuated to secure the assembly **100** in the wellbore and seal an area of interested located between the packing element **460** of the packer **400** and the packing element **685** of the anchor **600**. A treatment fluid may be supplied through the tubing string and the first packer **400**, and injected into the area of interest by the injection port **300**. Fluid communication between the packer **400** and the anchor **600** and the wellbore is closed when the packer **400** and the anchor **600** are in a set position. After a treatment operation is conducted, the mechanical force may be released and/or a downward or pull force may be applied to the tubing string to release the packing element **460** of the packer **400** and the slips **670** and the packing element **685** of the anchor **600** from engagement with the wellbore. Fluid communication is opened between the anchor **600** and the wellbore as the anchor **600** is unset and the ports **657** and **655** are aligned. Pressure equalization of the packer **400** is optional due to the pressure balanced inner mandrel. In an alternative embodiment, instead of a plug, the treatment fluid may be prevented from flowing through the assembly **100** using other embodiments described above, such as a ball and seat or an overpressure valve located at the lower end of the anchor **600** to open and close fluid communication therethrough.

A method of conducting a wellbore treatment operation is provided. Initially, a pack off assembly is lowered on a tubular string such as coiled tubing into a wellbore to a zone of interest. The assembly may include an optional unloader **200**, a first packer **400**A, an injection port **300**, a second packer **400**B, and an anchor **500** or **600**. The first packer **400**A is positioned in the up orientation and the second packer **400**B positioned in the down orientation. A seal, such as a plug, may be disposed at a bottom end of the assembly to prevent fluid communication therethrough. A mechanical force is applied to the assembly to place the assembly in tension. Sufficient mechanical force is applied to actuate the anchor **500**, thereby securing the assembly in the wellbore. The mechanical force also actuates the packers **400**A and **400**B, thereby urging the packing elements into sealing engagement with the surrounding wellbore and isolating the zone of interest therebetween. The packers **400**A, **400**B may be simultaneously actuated or in sequence. If the unloader **200** is used, the mechanical force actuates the unloader into a set position such that the unloader closes fluid communication between the interior of the assembly and the annulus surrounding the unloader above the first packer.

After the assembly is secured and the packing elements are set, the wellbore treatment operation may proceed by flowing a fluid through the tubular string and the assembly and injecting the fluid into the zone of interest via the injection port **300** located between the first and second packers **400**A, **400**B. After completion of the wellbore treatment operation, a mechanical force may be applied to relieve the tension in the assembly, thereby releasing the assembly. The mechanical force may be applied by pushing on the coiled tubing. If an unloader **200** is used, the mechanical force opens fluid communication between the interior of the assembly and the annulus surrounding the unloader above the first packer. In this respect, pressure is allowed to equalize between the interior and the exterior of the first packer. The mechanical force also unsets the first packer **400**A and the second packer **400**B, thereby releasing the sealed engagement of the packers with the wellbore. The mechanical force also releases the anchor **500** from engagement with the wellbore, thereby freeing the assembly from the wellbore. As described herein with respect to unsetting the assembly, the application of one or more mechanical forces to achieve the unsetting sequence may be accomplished merely by releasing the tension which had been applied to set the assembly in place initially, or may be supplemented by additional force applied by springs within the components and/or by setting weight down on the assembly. The assembly may then be removed from the wellbore or located to another area of interest to conduct another wellbore treatment operation as described above.

In one embodiment, a packer includes an outer housing; an inner mandrel movable relative to the outer housing; and a packing element actuatable by the relative movement between the outer housing and the inner mandrel, wherein the inner mandrel is balanced against movement in response to hydraulic pressure.

In one or more of the embodiments described herein, the packer may include a biasing member configured to bias the inner mandrel relative to the outer housing along a longitudinal axis.

In one or more of the embodiments described herein, the packer is actuated by using a mechanical force applied to overcome resistance from the biasing member.

In one or more of the embodiments described herein, the packer is actuated by overcoming resistance from the biasing member.

In one or more of the embodiments described herein, the packer may include a biasing member biasing the inner mandrel against the outer housing.

In another embodiment, a method of conducting a wellbore operation includes lowering an assembly on a tubular string into a wellbore, wherein the assembly includes a first packer, an injection port, a second packer, and an anchor; locating the injection port adjacent an area of interest in the wellbore; applying a mechanical force to the assembly, thereby actuating at least one of the first packer, the second packer, and the anchor; flowing a fluid into the area of interest via the injection port; exposing both sides of a piston in at least one of the first and second packers to a fluid pressure and balancing the piston against movement in response to the fluid pressure; and releasing the mechanical force being applied to the assembly, thereby releasing the assembly from secured engagement with the wellbore.

In one or more of the embodiments described herein, the second packer is actuated before the first packer.

In another embodiment, an assembly for conducting a treatment operation in a wellbore includes a tubing string; a first packer; a second packer actuatable using a mechanical force to seal an area of interest in the wellbore and is balanced against movement in response to hydraulic pressure; an injection port disposed between the first and second packers for injecting a treatment fluid into the area of interest; and an anchor for securing the assembly in the wellbore.

In one or more of the embodiments described herein, the first packer is a mechanically set packer.

In one or more of the embodiments described herein, the first packer is a hydraulic set packer.

In one or more of the embodiments described herein, the first packer comprises an anchor equipped with a packing element.

In one or more of the embodiments described herein, the second packer includes a debris barrier formed by an interface between two components.

In another embodiment, an assembly for conducting a treatment operation in a wellbore includes a tubing string; a first packer; a second packer actuatable using a mechanical force to seal an area of interest in the wellbore and is balanced against movement in response to hydraulic pressure; an injection port disposed between the first and second packers for injecting a treatment fluid into the area of interest; and an anchor for securing the assembly in the wellbore.

In another embodiment, a method of conducting a wellbore operation includes lowering an assembly on a tubular string into a wellbore, wherein the assembly includes an upper packer, a lower packer, an injection port disposed between the upper packer and the lower packer, and an anchor; locating the injection port adjacent an area of interest in the wellbore; applying a mechanical force to the assembly, thereby actuating at least one of the upper packer, the lower packer, and the anchor; flowing a fluid into the area of interest via the injection port; exposing both sides of a piston in at least one of the upper and lower packers to a fluid pressure and balancing the piston against movement in response to the fluid pressure; and releasing the mechanical force being applied to the assembly, thereby releasing the assembly from secured engagement with the wellbore.

In one or more of the embodiments described herein, the lower packer is actuated before the upper packer.

In one or more of the embodiments described herein, the upper packer is actuated using a higher, mechanical force than the lower packer.

While the foregoing is directed to embodiments of the invention, other and further embodiments of the invention may be devised without departing from the basic scope thereof, and the scope thereof is determined by the claims that follow.

We claim:

1. A packer, comprising:

an outer housing;

an inner mandrel movable relative to the outer housing; and

a packing element actuatable by the relative movement between the outer housing and the inner mandrel,

wherein the inner mandrel includes a first piston surface opposed to a second piston surface to prevent relative movement between the outer housing and the inner mandrel in response to fluid pressure, wherein a surface area of the first piston surface is provided to move the inner mandrel relative to the outer housing in a first direction and a surface area of the second piston surface is provided to move the inner mandrel relative to the outer housing in a second direction, and wherein the surface areas of the first and second piston surfaces are effectively equivalent to prevent relative movement between the outer housing and the inner mandrel in response to fluid pressure.

2. The packer of claim **1**, further comprising a biasing member configured to bias the inner mandrel relative to the outer housing along a longitudinal axis.

3. The packer of claim **2**, wherein the packer is actuated by using a mechanical force applied to overcome resistance from the biasing member.

4. The packer of claim **2**, wherein in the biasing member biases the inner mandrel against the outer housing.

5. The packer of claim **1**, wherein the packer includes a debris barrier formed by an interface between two components.

6. The packer of claim **1**, wherein the inner mandrel is moved relative to the outer housing by applying a tension force.

7. The packer of claim **1**, wherein the inner mandrel is pressure balanced by an equalization of pressure acting on the inner mandrel.

8. The packer of claim **1**, wherein the surface areas of the first and second piston surfaces provide an effective zero net fluid force acting on the inner mandrel in response to the fluid pressure.

9. A method of conducting a wellbore operation, comprising:

lowering an assembly, wherein the assembly includes a first packer and a second packer;

actuating at least the first packer into a set position; and

pressure balancing a first piston surface opposed to a second piston surface to provide an effective zero net fluid force acting on at least the first packer in response to the fluid pressure.

10. The method of claim **9**, wherein the second packer is actuated before the first packer.

11. The method of claim **9**, wherein the first and second piston surfaces are disposed on a mandrel in at least the first packer.

12. The method of claim **9**, wherein the assembly includes an anchor.

13. The method of claim **12**, further comprising actuating the anchor by applying a mechanical force to the assembly.

14. The method of claim **9**, wherein the assembly includes an injection port disposed between the first packer and the second packer.

15. The method of claim **14**, further comprising locating the injection port adjacent an area of interest in a wellbore.

16. The method of claim **15**, further comprising flowing a fluid into the area of interest via the injection port.

17. The method of claim **9**, wherein actuating at least the first packer includes applying a mechanical force to the assembly to secure engagement with the wellbore.

18. The method of claim **17**, wherein the first packer is actuated using a higher, mechanical force than the second packer.

19. The method of claim **17**, further comprising releasing the mechanical force being applied to the assembly to release the assembly from secured engagement with the wellbore.

20. The method of claim **9**, wherein the first packer is an upper packer and the second packer is a lower packer.

21. The method of claim **9**, wherein the first packer is a lower packer and the second packer is an upper packer.

22. An assembly for conducting a treatment operation in a wellbore, comprising:

a first packer;

a second packer, wherein the second packer is actuatable to seal an area of interest in the wellbore and the second packer is pressure balanced to provide an effective zero net fluid force acting on the second packer in response to fluid pressure;

an injection port disposed between the first and second packers for injecting a treatment fluid into the area of interest; and

an anchor for securing the assembly in the wellbore.

23. The assembly of claim **22**, wherein the first packer is a mechanically set packer.

24. The assembly of claim **22**, wherein the first packer is a hydraulic set packer.

25. The assembly of claim **22**, wherein the first packer comprises an anchor equipped with a packing element.

26. The assembly of claim **22**, wherein the second packer includes a debris barrier formed by an interface between two components.

27. The assembly of claim **22**, wherein the first packer is oriented in an upside down direction relative to the second packer.

28. The assembly of claim **22**, wherein the second packer includes:

an outer housing;

an inner mandrel movable relative to the outer housing; and

a packing element actuatable by the relative movement between the outer housing and the inner mandrel,

wherein the inner mandrel is pressure balanced to prevent relative movement between the outer housing and the inner mandrel in response to hydraulic pressure.

29. The packer of claim **28**, wherein the second packer further comprises a biasing member configured to bias the inner mandrel relative to the outer housing along a longitudinal axis.

30. The packer of claim **29**, wherein the second packer is actuated by using a mechanical force applied to overcome resistance from the biasing member.

31. The packer of claim **29**, wherein in the biasing member biases the inner mandrel against the outer housing.

32. The packer of claim **28**, wherein the inner mandrel is moved relative to the outer housing by applying a tension force.

33. The assembly of claim **22**, wherein the second packer is pressure balanced by an equalization of pressure forces in the second packer.

34. The assembly of claim **22**, wherein the second packer is actuatable using a mechanical force.

35. A method of conducting a wellbore operation, comprising:

lowering an assembly, wherein the assembly includes a first packer and a second packer;

actuating at least the first packer into a set state;

exposing two opposing effectively equivalent piston areas of at least the first packer to a fluid pressure to prevent changing at least the first packer from the set state in response to the fluid pressure and pressure balancing the two piston areas.

36. The method of claim **35**, wherein the first packer is an upper packer and the second packer is a lower packer.

37. The method of claim **35**, wherein the first packer is a lower packer and the second packer is an upper packer.

38. The method of claim **35**, wherein the two opposing piston areas of at least the first packer provide an effective zero net fluid force acting on at least the first packer in response to the fluid pressure.

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